Hydrocarbon and By-Product Reserves in British Columbia

2012 | BC Oil and Gas Commission

BC Oil & Gas COMMISSION

About the

BC Oil and Gas Commission

The BC Oil and Gas Commission (Commission) is the provincial single-window regulatory agency with responsibilities for regulating oil and gas activities in British Columbia, including exploration, development, pipeline transportation and reclamation.

The Commission's core services include reviewing and assessing applications for industry activity, consulting with First Nations, cooperating with partner agencies, and ensuring industry complies with provincial legislation and all regulatory requirements. The public interest is protected by ensuring public safety, respecting those affected by oil and gas activities, conserving the environment, and ensuring equitable participation in production.

For general information about the Commission, please visit: www.bcogc.ca or phone 250-794-5200.

Mission

We regulate oil and gas activities for the benefit of British Columbians.

We achieve this by:

- Protecting public safety,
- Respecting those affected by oil and gas activities,
- Conserving the environment, and
- Supporting resource development.

Through the active engagement of our stakeholders and partners, we provide fair and timely decisions within our regulatory framework.

We support opportunities for employee growth, recognize individual and group contributions, demonstrate accountability at all levels, and instill pride and confidence in our organization.

We serve with a passion for excellence.

Vision

To be the leading oil and gas regulator in Canada.

Values

Respectful

Accountable

Effective

Efficient

Responsive

Transparent

Table of Contents

Hydrocarbon and By-Product Reserves

The oil and gas production and remaining recoverable reserve numbers are a current reflection of the state of development in British Columbia. As drilling continues to define additional prospective lands, resource estimates become proven reserves, substantiated with production volumes and geological data.

This report summarizes oil and gas production and remaining recoverable reserves in British Columbia providing assurance of supply for the development of policy, regulation and investment. It also emphasizes the growth and future potential of unconventional resources as a long term source of natural gas for the province.

Estimates of British Columbia's natural gas, oil, condensate, and associated by-product reserves are presented in this report as of Dec. 31, 2012. The estimates have been prepared by the BC Oil and Gas Commission (Commission) using accepted reserve evaluation methods (including COGEH and SPEE Monograph 3).

The reserve numbers represent proved plus probable (P50) reserves recoverable using current technology under present and anticipated economic conditions. Reserves are proven by drilling, testing and/or production and include proven undeveloped (PUD) reserves interpreted from geological data and/or analogous production.

Executive Summary

British Columbia's remaining reserves as of Dec. 31, 2012, together with a comparison of the Dec. 31, 2011 reserves, are summarized in Table 1.

Reserves increased for all products, mainly due to significant expansion and development of the regional Montney formation, contributing to gas, condensate, natural gas liquids (NGL) and oil production. Unconventional reservoirs have tremendous growth potential, with booked reserves representing less than one per cent of current total resource estimates (Appendix B, Table B-4: Summary of Unconventional Plays).

Detailed information on the reserves and reservoir parameters for each field/pool in B.C. is provided in Appendix C. Historical data from previous hydrocarbon reports published by the Commission is summarized in Appendix A.

Table 1: Remaining Reserves as of December 31, 2012

	2011	2012
Oil	18.2 10^6 m^3 (114.5 MMSTB)	19.1 10^6 m^3 (120.2 MMSTB)
Gas	974.9 10^9 m^3 raw (34.6 TCF)	1,138.5 10^9 m^3 raw (40.2 TCF raw)
Condensate	11.3 10^6 m^3 (71.1 MMSTB)	16.2 10^6 m^3 (101.9 MMSTB)
NGL	30.5 10^6 m^3 (192.2 MMSTB)	44.0 10^6 m^3 (277.0 MMSTB)
Sulphur	13.7 10^6 tonnes (13.5 MMLT)	15.7 10^6 m^3 (15.5 MMLT)

Figure 1: 2012 Targeted Plays by Wells Rig Released

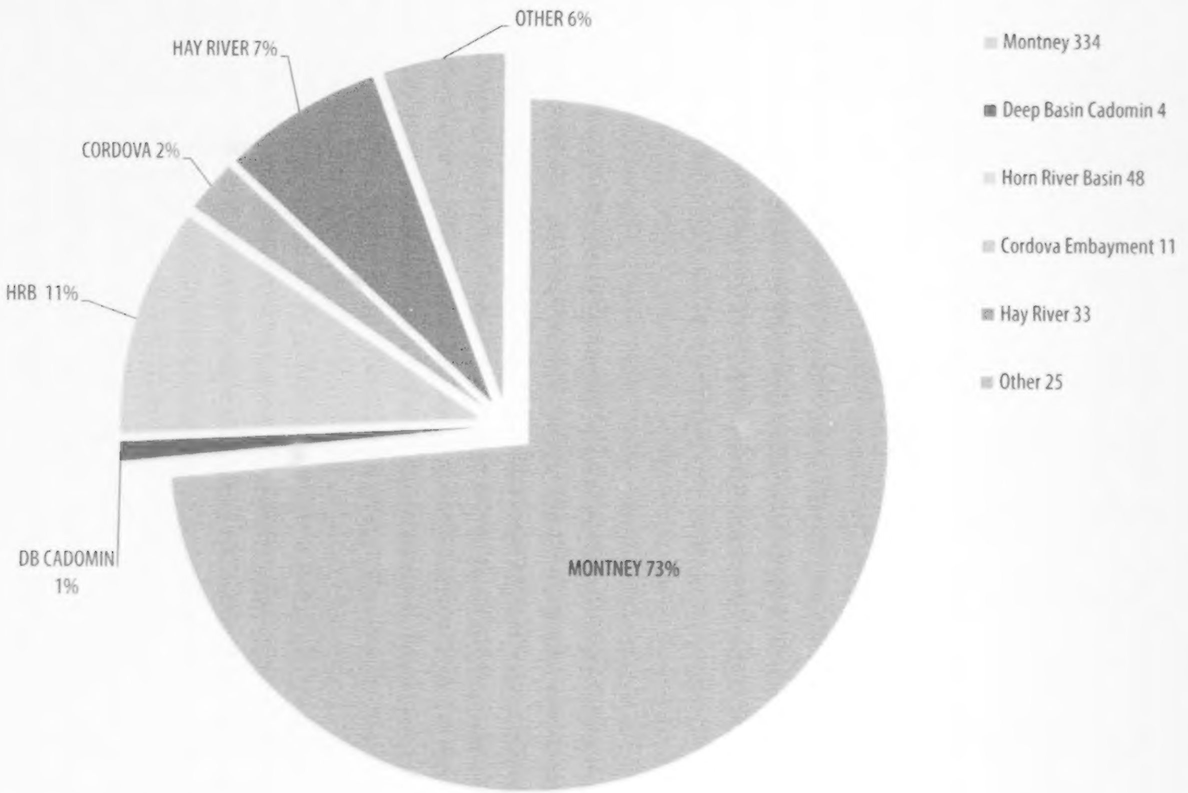
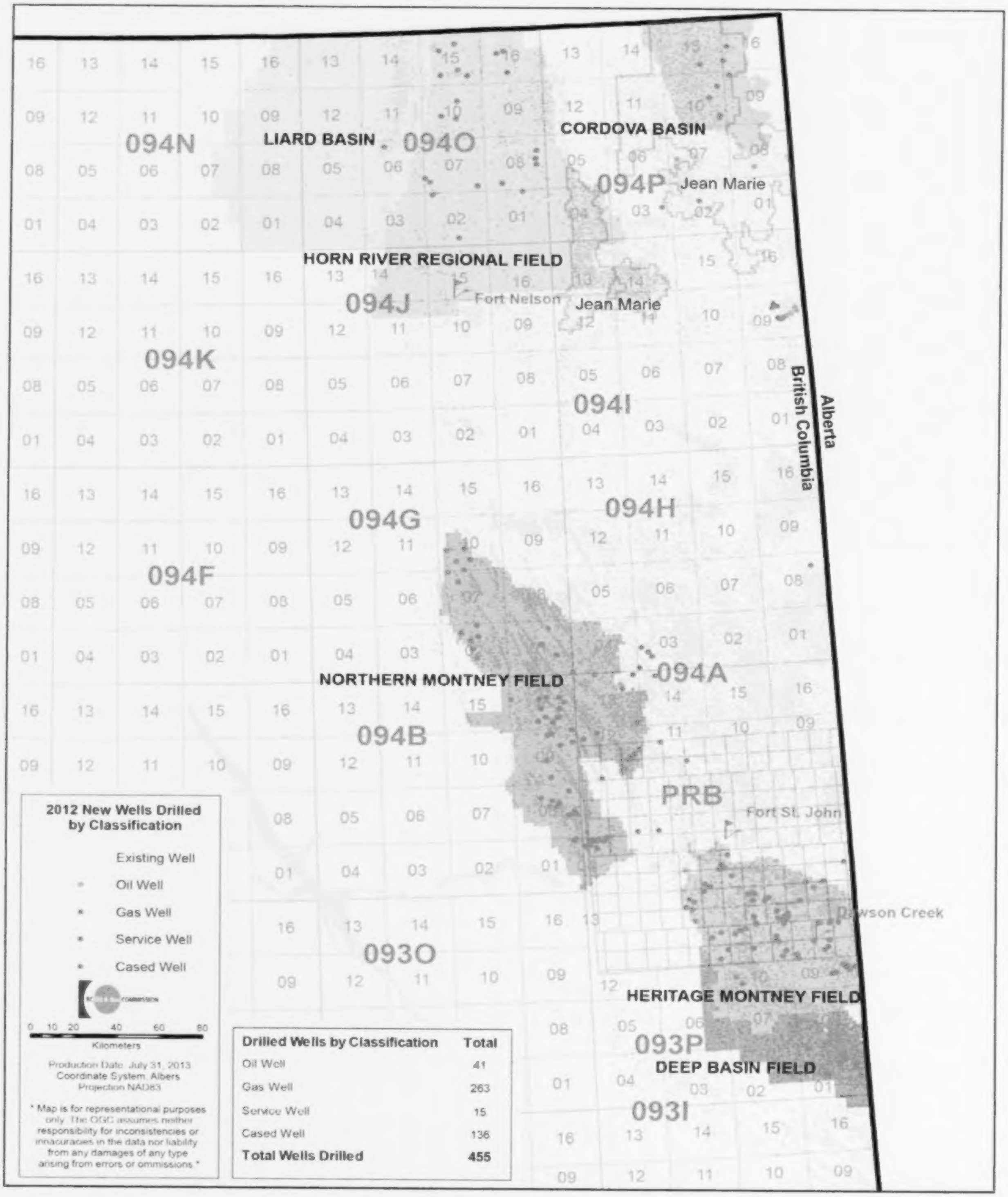


Figure 1 identifies the targeted plays for wells drilled in 2012. The Montney was the dominate zone targeted (73 per cent), with drilling activity also occurring in the Horn River Basin (HRB) and the Hay River Bluesky "A" oil pool. A total of 455 wells were drilled in B.C. in 2012.

The location and type of wells drilled in 2012 is presented in Figure 2, along with the location and areal extent of the major unconventional fields (Montney, Horn River, Liard, Cordova Embayment, Jean Marie and Deep Basin Cadomin). Of the 334 wells drilled targeting the Montney, 60 per cent were located in the southern portion of the play (Heritage field) and 40 per cent to the north (Northern Montney field). Recent discovery of an oil leg within the Montney led to the drilling of 10 Montney oil wells (24 per cent of total oil wells drilled). The most active area of oil drilling remains the Hay River – Bluesky "A" pool (18 wells, 44 per cent of total oil wells). There were also 15 service wells drilled in 2012, down 46 per cent from 2011, principally a reduction in drilling for source water. Drilling of disposal wells (five) and injector wells (10) remained consistent with 2011 numbers. Of the five disposal wells drilled in 2012, three were within the Montney Play Trend (northern region) and two were located within the Horn River Basin. All of the injector wells drilled support the Hay River Bluesky "A" pool waterflood.

Figure 2: 2012 Wells Drilled by Type



Drilled Wells by Classification	Total
Oil Well	41
Gas Well	263
Service Well	15
Cased Well	136
Total Wells Drilled	**455**

A. Gas Reserves

As of Dec. 31, 2012, the province's remaining raw gas reserves are 1,138.5 10^9 m^3, a 16 per cent increase over the 2011 value. The trend of upward reserve revisions continues largely due to successful development of unconventional Montney tight gas and Horn River shale gas, with continued learnings applied to the use of horizontal drilling and hydraulic fracturing technology.

Figure 3 illustrates the distribution of remaining gas reserves, with approximately one-third coming from each of the large unconventional plays, Montney and Horn River, and the remaining third from existing conventional reserves. Unconventional sources are expected to further dominate with new activity and the continued depletion of conventional pools.

Figure 3: Remaining Gas Reserves - Conventional versus Unconventional

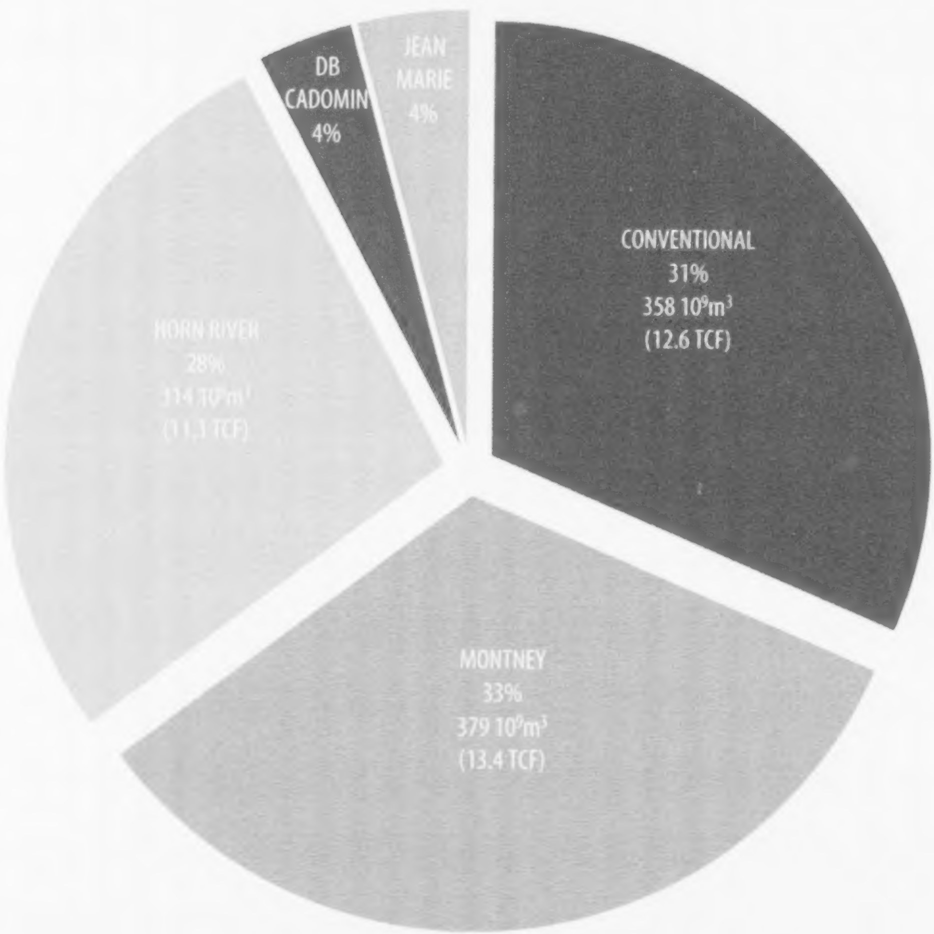
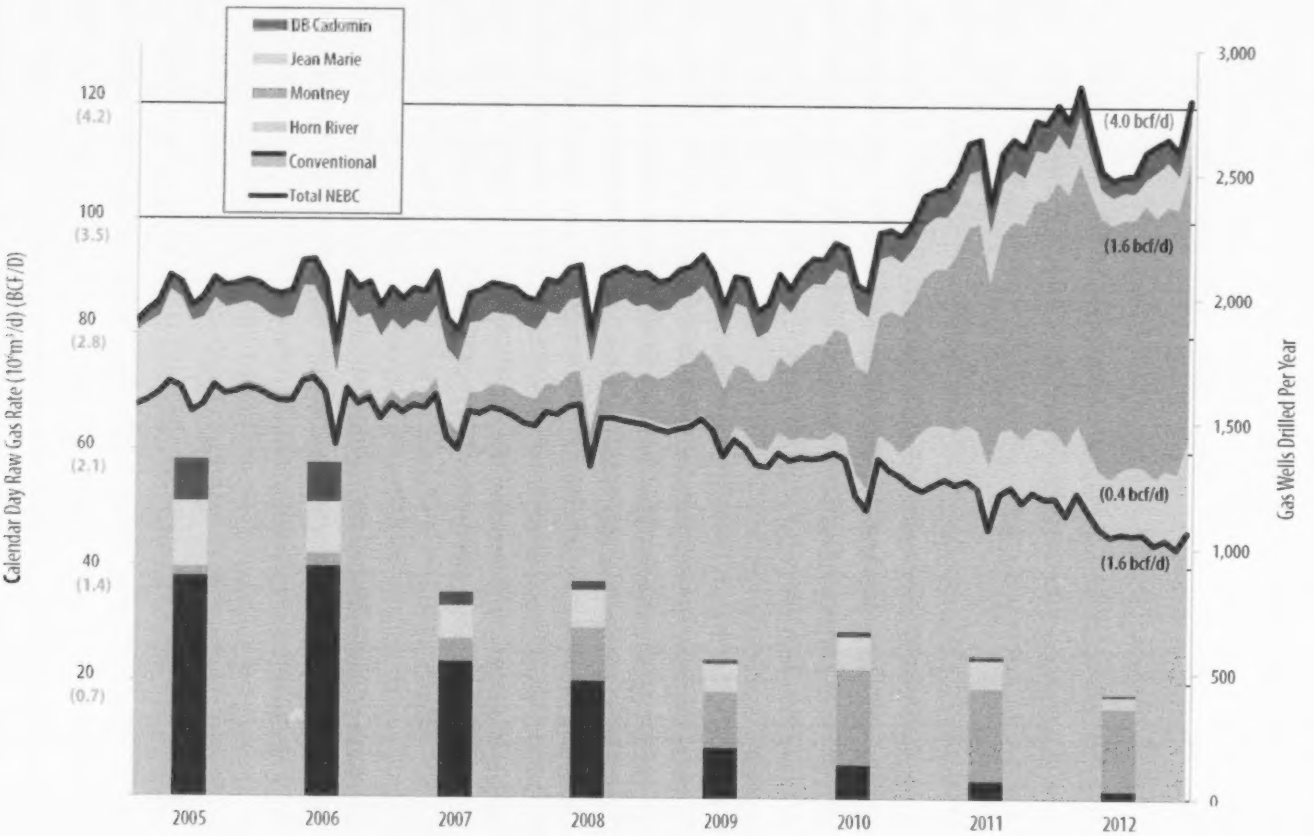


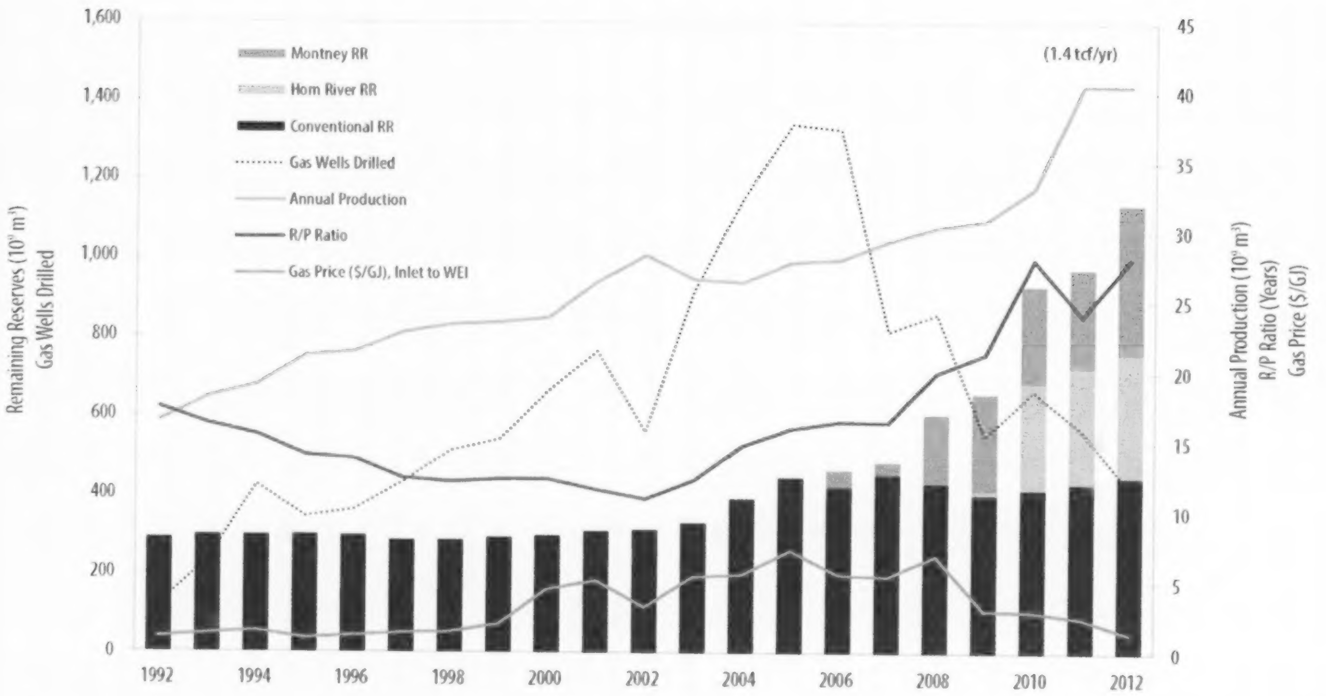
Figure 4: Raw Gas Production and Gas Wells Drilled Per Year



The progression from conventional vertical drilling of "high" permeability (1-10 mD) gas reservoirs to "low" permeability (<500 nD) regionally extensive unconventional gas basins is highlighted in Figure 4. The Montney, Horn River, Jean Marie and Deep Basin Cadomin comprise the unconventional production shown in Figure 4, with the remainder combined as conventional. In 2005, unconventional Jean Marie and Deep Basin Cadomin production accounted for 20 per cent of B.C.'s total, with the majority of B.C.'s production coming from conventional gas wells. Development of the extensive Montney and Horn River regional plays commenced in 2007/2008, while conventional drilling continued to decrease. Currently, unconventional plays account for 60 per cent of B.C.'s total gas production. The Montney contributed 40 per cent and was the target of 73 per cent of wells drilled in 2012. Conventional production is declining at eight per cent per year with minimal drilling occurring in 2012. Total natural gas production for 2012 was 40.5 10^9 m^3 (1.4 TCF), steady with 2011 annual production.

Figure 5 provides a review of the Commission's reserve bookings over time, with an emphasis on "unconventional" Montney and Horn River reserves versus all other reserves grouped as "conventional". Looking back to 1992, remaining reserves (RR) were fairly consistent until 2003 when gas price and drilling began to increase dramatically. Between the years 2003-2006, activity reached record levels, (1,300 gas wells drilled in 2006), with predominant targets being: shallow Cretaceous (Notikewin, Bluesky Gething) and Triassic (Baldonnel and Halfway), Deep Basin Cadomin and Nikanassin and Jean Marie platform and bank-edge. However, in 2007, the onset of horizontal drilling with hydraulic fracture stimulation, applied to unexploited shale gas and ultra low permeability gas reservoirs, created a new supply of gas, not just in B.C. but across North America. Gas prices dropped with the large influx of unconventional gas to market to less than \$2/MCF. Despite the deflation in gas price, annual production in B.C. has risen 40 per cent from 2007 to 2012, with the majority, 60 per cent, now coming from unconventional reservoirs.

Figure 5: Historical Gas Development in B.C.



The R/P (reserves to production) ratio has increased significantly in the last five years, (from 16 years of supply) to 28 years, as unconventional reserve bookings have begun to replace and surpass conventional reserves. Despite limited permeability, unconventional wells with long reach horizontal wellbores and large stimulated reservoir volumes tend to access more reserves on average than typical conventional wells. Thus reserves, per well drilled, have increased. This trend of increasing unconventional reserves in B.C. is expected to continue, given the large, extensive resource estimates of unconventional gas (Appendix B, Table B-4) and the potential influence liquefied natural gas exports will have on gas prices. As development continues, more gas resources will become proven reserves.

Significant gas reserves increases occurred in 2008 with the booking of Montney reserves and in 2010 with the introduction of Horn River reserves. For 2012, remaining reserves continue to rise (up 16 per cent), due principally to a review of the Montney, with new drilling and the booking of proven undeveloped reserves (PUDs) following SPEE statistical methods.

For unconventional reservoirs, the effectiveness of the completion is as important a factor as the quality of the reservoir. Hence, completion parameters such as number of fracture stages and fluid pumped are included in this report, (in the Unconventional Play sections following), as indicative of the stimulated rock volume and ultimate recoverable reserves.

Geology, drilling and completions, production and reserve evaluation methodology are discussed in the following sections for the Montney, Horn River, Liard and Cordova Embayment Unconventional Plays. A table comparing the parameters of each Unconventional Play is provided in Appendix B, Table B-4.

Montney - Unconventional Tight Gas Play

The unconventional Montney Play Trend represents 33 per cent (13.4 TCF) of the province's remaining recoverable raw gas reserves. In 2012, 0.6 TCF was produced from the Montney, accounting for 40 per cent of total gas production in the province.

Geology

The unconventional Lower Triassic Montney formation includes dry gas, liquids rich gas and oil in over-pressured siltstones along an extensive 29,850 kilometres $(km)^2$ play trend that stretches northwest 200 km from the B.C.-Alberta border near Dawson Creek to the B.C. foothills (Figure 6a).

Figure 6a. Unconventional Montney Play Trend

The unconventional Montney is confined to the northwest by outcrop and to the southwest by depth as it deepens to beyond 4,000 m Total Vertical Depth (TVD). The eastern play limit is defined by the transition to a normal formation pressure regime.

Development of the unconventional Montney began in 2007 and by 2012 the Montney has become the single largest contributor to provincial natural gas production volumes. By the end of 2012, the Montney was producing at approximately 45.3 $10^6 m^3/d$ (1.6 BCF/D) from 1,270 wells and surpassed a cumulative production of 45.4 $10^9 m^3$ (1.6 TCF). For regulatory purposes, the play trend has been subdivided into two main regional fields; the Heritage Field (south) and the Northern Montney Field (north) (Figure 6b).

The regional Heritage Field is comprised of a single pool (Montney "A") which has both dry and wet gas and a small oil leg. For regulatory purposes and in this report, commonly referenced Upper, Middle and Lower Montney are grouped as a single formation. The Heritage Field covers a large area (561,120 ha) and there is a significant range in reservoir parameters. As a general rule, porosity and permeability are better to the northeast while formation pressure increases with depth of burial to the southwest, especially where the play quickly transitions into the B.C. portion of the Deep Basin. There is a significant gas liquids component to the Montney gas in the northeast part of the field in the geographic areas of Septimus, Sunrise and Parkland and there is a newly defined oil leg that is currently being evaluated at Tower (see Oil Reserves Discussion).

The regional Northern Montney Field has three gas pools: Doig Phosphate-Montney (DPM) "A", Montney "A" and Montney "B". The large expanse of the field (845,156 ha) translates into significant ranges for the reservoir parameters. Reservoir conditions are further complicated to the west where a portion of the Northern Montney resides within the disturbed belt of the Northern Rockies. As such, the western part of the field can be subject to substantial formation over-pressure, structural thickening and naturally occurring fractures and faults. There are also significant natural gas liquids and condensate production volumes, especially in the geographic areas of north Altares and Blueberry.

The Montney Formation Play Atlas, available in the Reports section of the Commission website, provides detailed geological mapping of the Unconventional Montney Play Trend. Table 2 provides a range of reservoir parameters for the Heritage (south) and Northern Montney regional fields.

Expansion of unconventional Montney development outside regional fields has occurred at Nig Creek (northeastern edge of Northern Montney Field) and Attachie and Monias (between Heritage and Northern Montney). Reserves for these three pools are provided by field/pool in Appendix C.

Figure 6b: Montney Regional Fields and Dry/Wet/Oil Distribution

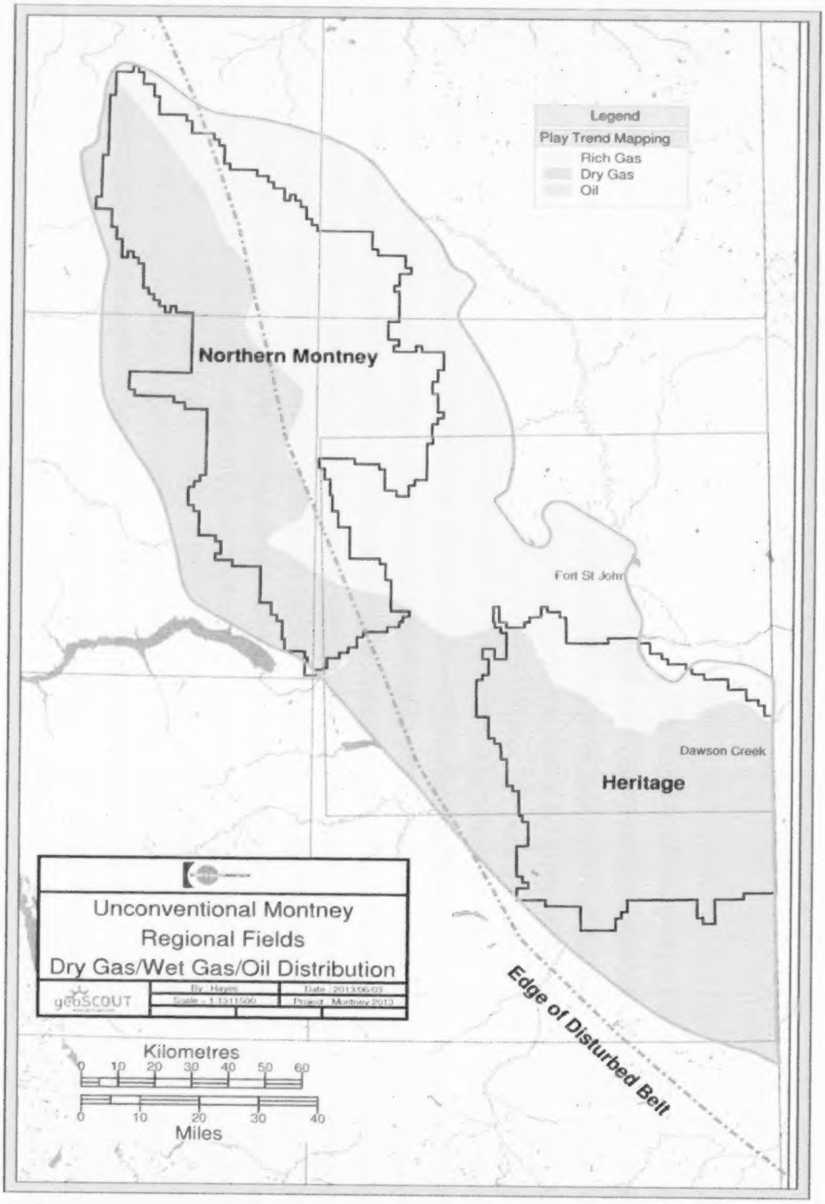


Table 2: Montney Reservoir Parameters

Reservoir Data	Heritage	Northern Montney
Depth Range	1,800 – 3,200 m	2,000 – 2,400 m
Gross Thickness	30 – 300 m	30 – 300 m
TOC Range	~2%	~2%
Porosity	2 – 9%	2 – 9%
Water Saturation	25%	25%
Pressure	20 – 50 MPa	30 – 44 MPa
Pressure Regime	Over Pressure	Over Pressure
Temperature	60 – 100° C	60 – 75° C
H_2S	Less than 0.3%	Less than 0.3%
CO_2	Less than 1% (max 5%)	Less than 1% (max 5%)

Drilling and Completions

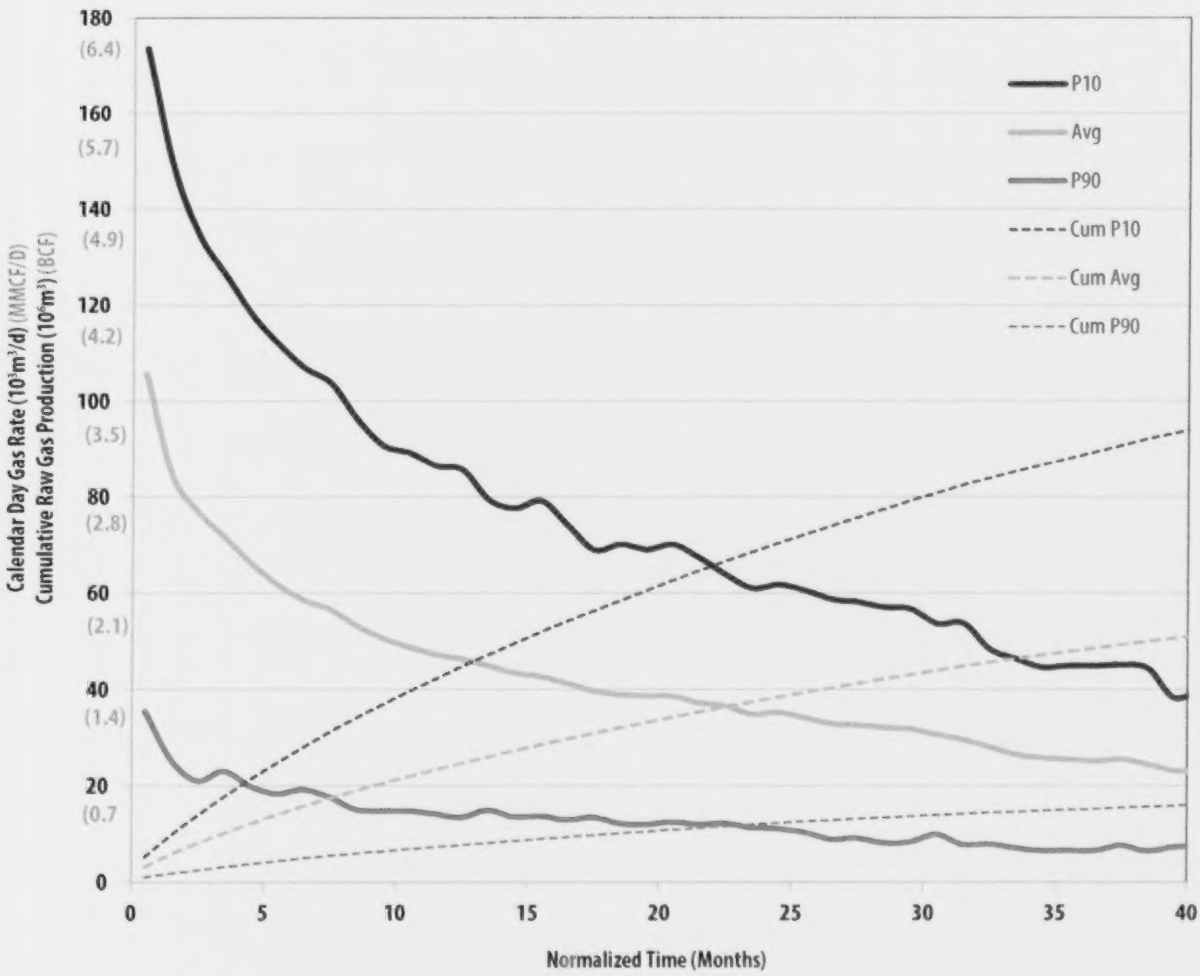
Significant efforts have been made to optimize recovery in the Montney, employing a host of drilling spacing and completion techniques. Table 3 summarizes the range of drilling and completion parameters for an 800 well dataset completed in 2010-2012. A typical horizontal well, completed between 2010-2012, has an approximate 1,600 m cased hole lateral with 10 fracture stages pumped. Open hole completions were conducted in 25 per cent of Montney wells across the play, predominately in the southern Heritage field. Approximately 50 per cent of Montney completions to date were slickwater based, while the remaining 50 per cent used additional additives such as linear or cross-linked gel to enhance viscosity. Addition of energized gas to the fracture fluid (CO_2, N_2 or combination) is also common, reported in 40 per cent of Montney completions. Gelled and energized completions use less than 2,000 m^3 of water per well on average (400 well dataset), while slickwater treatments are more water intensive, using approximately 9,000 m^3/well on average (500 well dataset). This is significantly less than the average water pumped in the Horn River (64,000 m^3/well) 2010/12 average. In June 2013, the Commission introduced online submission of detailed completions data (INDB 2013-03) to improve access and tracking of key parameters. Additionally, disclosure of the chemicals included in each fracture treatment is available in the public database www.fracfocus.ca.

Table 3: Montney Drilling and Completions (2010-2012)

Drilling Data	
Wells/pad	Up to 20
Well density	Up to 16 wells per GSU, average 2.5 wells per GSU
HZ length	Up to 3,000 m, average ~1,600 m
Wellbore	75% Cased / 25% Open hole
Completion Data	
Number of stages	Up to 36, average 10
Fracture fluid	Slickwater, linear or cross-linked gel Energized or foam with CO_2 and/or N_2
Pump rate	2 – 15 m^3 per min, average 6 m^3 per min
Average water per well	<2,000 m^3 gel/foam; 9,000 m^3 slickwater
Average sand per well	1,300 T

Figure 7 presents typecurves of Montney production across the Heritage and Northern Montney regional fields, based on a sample size of 1,000 wells (results were very similar when calculated separately). Calendar day raw gas rate and cumulative gas production (dashed lines) are plotted versus normalized time in Figure 7, with typecurves generated to summarize the average, P10 and P90 well performance. The average well initial rate is just over 100 $10^3m^3/d$ (3.7 MMCF/D), declining sharply to under 50 $10^3m^3/d$ (1.7 MMCF/D) in the first year. After 40 months, the average well has produced 50 $10^3m^3/d$ (1.7 BCF), with 90 per cent of the wells (P90) producing more than 16 $10^3m^3/d$ (0.6 BCF) and 10 per cent of the wells (P10) producing 94 $10^3m^3/d$ (3.3 BCF) or more.

Figure 7: Montney Horizontal Well Typecurves



Estimated ultimate recovery (EUR) for each of the Montney regional fields (Heritage, Northern Montney) was estimated using SPEE Monograph 3 guidelines. Modified Arps and Stretch Exponential forecasting methods were used with an economic cutoff of 100 MCF/D. Rounding to the nearest BCF, a mean EUR of five BCF per well was forecast and found to be consistent from pool to pool with slight variation in unrounded results.

Following the guidance in Monograph 3, proved undeveloped (PUD) reserves were assigned to the Heritage and Northern Montney regional fields based on development maturity (calculated using P90/P10 ratios and well count). Heritage Montney falls into the Monograph's "mature" category and Northern Montney is "early" phase. Maps depicting the variation in well density in Heritage and Northern Montney (up to 16 wells/GSU) are provided in Figures B-3 and B-4 of Appendix B.

An average OGIP of approximately 250 BCF/GSU was calculated for the B.C. Montney from a collaborative study, The Ultimate Potential for Unconventional Petroleum from the Montney Formation, published by the Commission, National Energy Board, Alberta Energy Regulator and BC Ministry of Natural Gas Development in November 2013. As of 2012, the total booked EUR for the Montney is 15 TCF, which represents less than one per cent recovery of the total prospective resource estimate in B.C. of the 1965 TCF.

A detailed discussion of the methodology and results is provided in Appendix B, including cumulative probability distributions, histograms and well density maps.

Horn River Basin - Unconventional Shale Gas Play

The Horn River Basin (HRB) represents 28 per cent (11.1 TCF) of the Province's remaining recoverable raw gas reserves. In 2012, 0.1 TCF was produced from the Muskwa-Otter Park and Evie formations within HRB, accounting for 11 per cent of total production in the province.

Table 4: Horn River Shale Reservoir Parameters

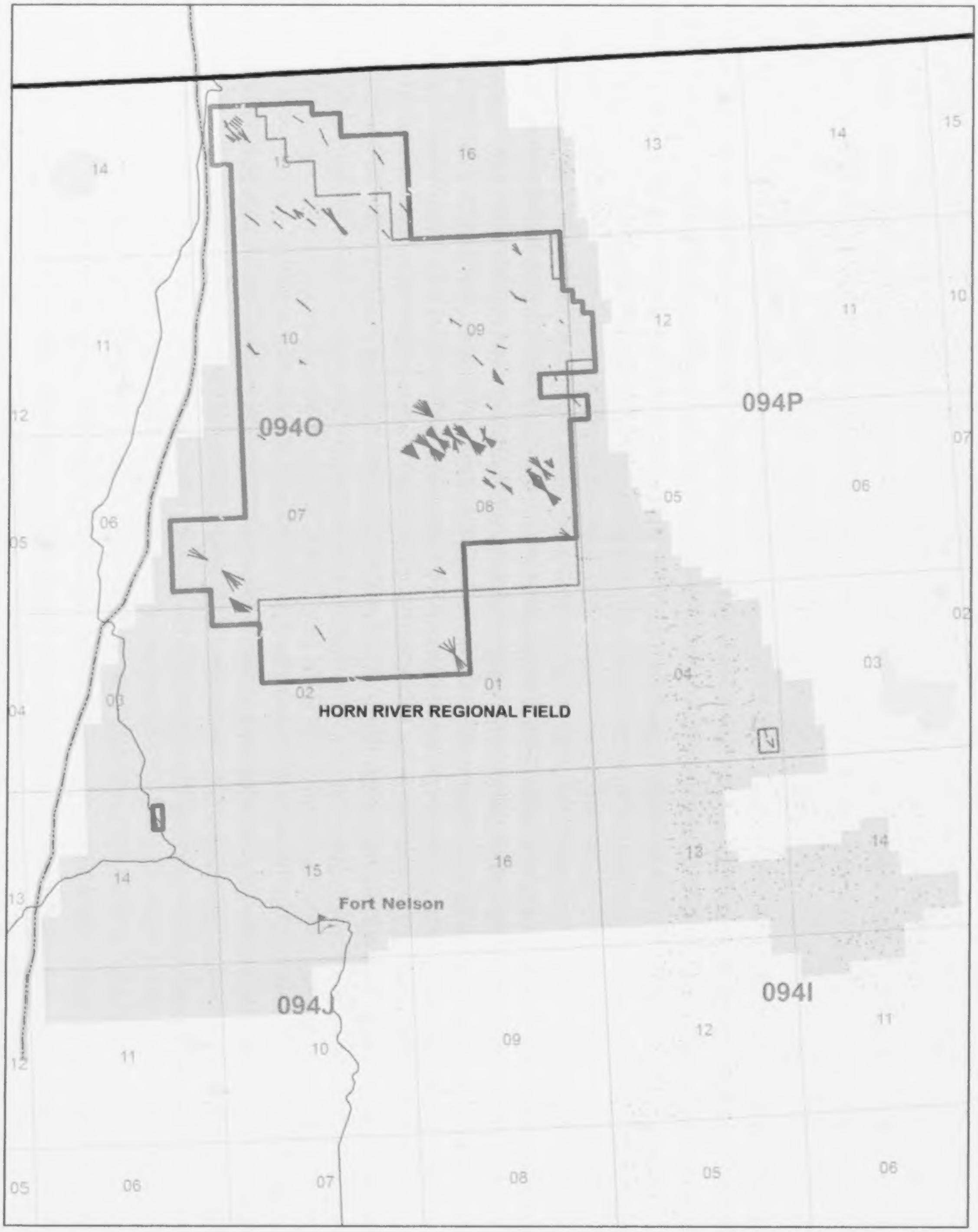
Reservoir Data	
Depth Range	1,900 – 3,100 m
Gross Thickness	140 – 280 m
TOC Range	1 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	20 – 53 MPa
Pressure Regime	Normal - Over Pressure
Temperature	80 – 160° C

Geology

The HRB is an unconventional shale play targeting dry gas from mid-Devonian aged overpressured shales of the Muskwa, Otter Park and Evie Formations. Situated in the northeast of the Province (see Figure 2), the Horn River Basin is confined to the west by the Bovie Lake Fault Zone and to the East and South by the time equivalent Devonian Carbonate Barrier Complex. Stratigraphically, the organic rich siliciclastic Muskwa, Otter Park and Evie shales of the Horn River group are overlain by the Fort Simpson shales and underlain by the Keg River platform carbonates.

Muskwa and Otter Park formations were mapped in combination and analyzed as one interval, with the Evie formation evaluated and mapped separately. A regional mapping project is underway, with a Horn River Play Atlas to be published by the Commission in the near future. Mapping completed thus far has defined areas of reservoir variability within the Basin, particularly within the Otter Park Formation. Figure 10 denotes wells drilled and the pool designation areas (PDAs) for the Muskwa-Otter Park and Evie shale formations. A general range of reservoir parameters is provided in Table 4.

Figure 8: Pool Designation Areas (PDA) within the Horn River Basin



Due to the depth and corresponding high temperature and pressure of the Muskwa, Otter Park and Evie shale formations in the HRB, the recoverable gas is sweet dry gas, greater than 87 per cent methane, with trace amounts of ethane, (0.2 per cent) and heavier hydrocarbon components, C_{3+}, (<0.1 per cent). The majority of gas analyses show no H_2S, or very low levels, with slightly higher values in the Evie, (Table 5). CO_2 content in the recoverable gas averages 10 per cent in the Muskwa-Otter Park formations and 12 per cent in the Evie formation, and generally increasing with depth in the Basin. The average values and range of components typically found in Horn River gas are summarized in Table 5.

Table 5: Horn River Gas Composition, Mole Percentage

Gas Composition, Avg (Min-Max) %	Muskwa-Otter Park	Evie
Methane (C_1)	89 (71 – 95)	87 (75 – 98)
Ethane (C_2)	**0.2 (0.01 – 3)**	**0.2 (0.01 – 7)**
NGLs (C_{3+})	0.05 (0 – 4)	0.07 (0 – 4)
CO_2	**10 (4 – 22)**	**12 (0 – 19)**
H_2S	0 (0 – 0.1)	0.07 (0 – 0.1)

Development History

The HRB has been of interest since 2005, when horizontal drilling and multi-stage hydraulic fracturing technology from the analogous Barnett shales in Texas was applied to investigate economic recovery. Prior to this, there were very few penetrations in the Basin as operators were targeting Devonian pinnacle reefs, with shale then considered a seal and source rock for gas.

As of December 31, 2012, 265 horizontal and 63 vertical wells have been drilled across the Basin targeting shale gas. The play concept has extended several kilometres south and east of the prexisting production as a result of 2012 drilling activity. A considerable quantity of well data, held confidential under the terms of Special Project Innovative Technology approvals, is now publicly available.

Drilling and Completions

Advancements in horizontal well technology and hydraulic fracturing were key to unlocking the reserves in the HRB. Up to 16 horizontal wells per pad have been drilled, receiving multi-stage slickwater completion programs with 18 pumping stages, 64,000 m^3 of water and 3,700 T of sand on average, based on stats for 130 wells completed between 2010-2012. Microseismic monitoring is used extensively in the HRB to identify faults, optimize completion design and study fracture growth. To date, the overlying Ft. Simpson shale has been demonstrated to be a highly effective fracture barrier.

To date, the majority of wells in the HRB are completed through casing (95 per cent), with open hole completions conducted in five per cent of wells. The fracture fluid is predominately slickwater, with N_2 gas, an energizer, used in a few wells. On average, 40 per cent of fracture load water is flowed back to surface on clean up and production, with the majority recycled.

Water Usage and Disposal

The eastern flank of the HRB contains favorable Mississippian strata (Debolt formation) for sourcing and disposing of water necessary for large scale hydraulic fracture operations. Mississippian sourced water in the Horn River area is non-potable (15,000 – 40,000 mg/l total dissolved solids), significantly reducing the demand for usable water from other sources. This extensive deep subsurface Debolt regional aquifer essentially allows source/disposal recycling of fracture water.

Table 6: Horn River Shale Drilling and Completions (2010-2012)

Drilling Data	
Wells per pad	Up to 16
Well spacing	100 – 600 m, average 300 m
HZ length	Up to 3,100 m, average ~1,500 m
Wellbore	Cased
Completion Data	
Completion method	Perf and plug
Fracture	Slickwater
Number of stages	Up to 31, average 18
Pump rate	8 – 16 m^3 per min
Water per well	Average 64,000 m^3
Sand per well	Average 3,700 T

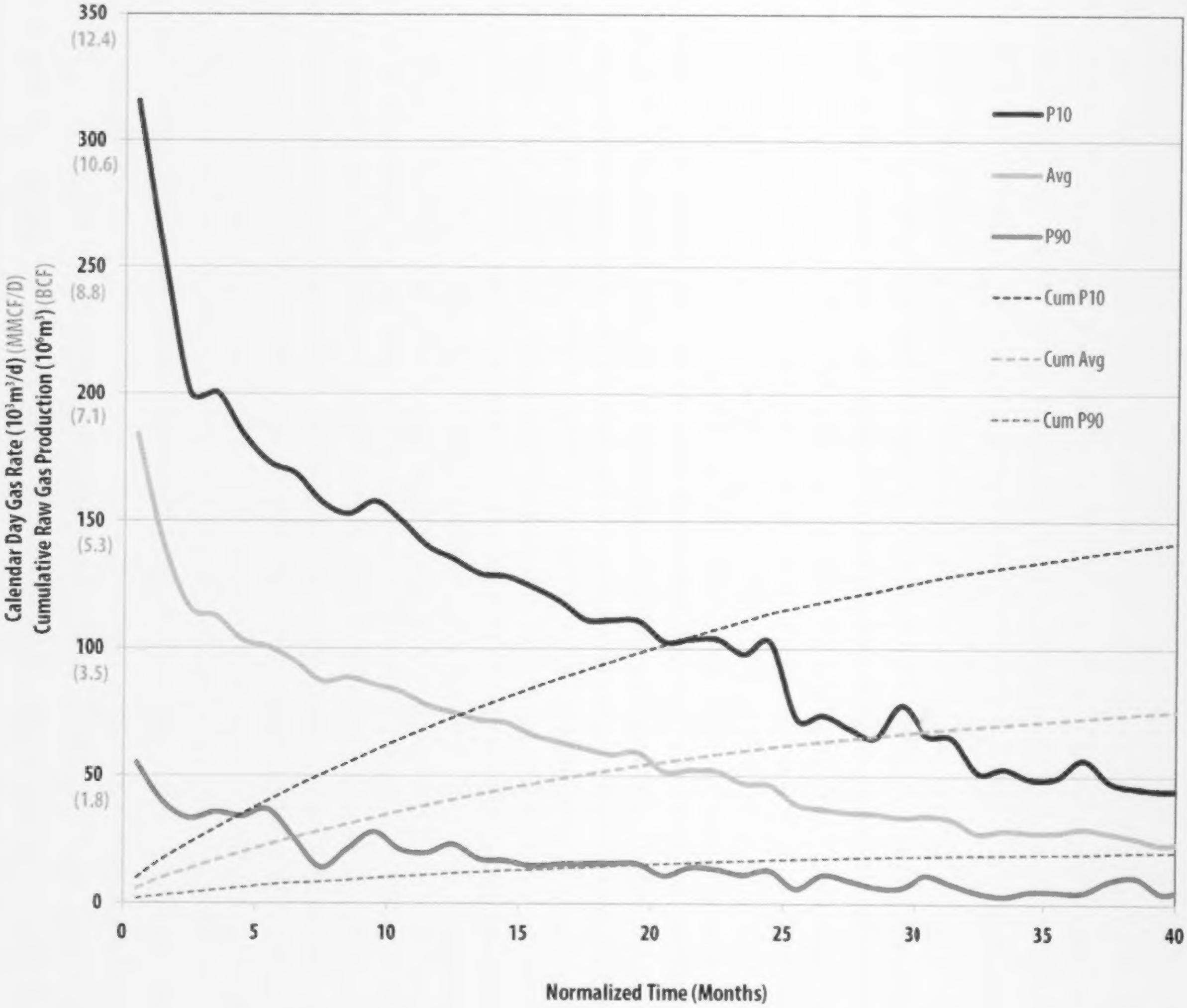
Production

A typical horizontal well in the HRB exhibits an initial peak gas rate of 200 $10^3m^3/d$ (7 MMCF/D), declining 40 per cent in the first producing year, and gradually reaches boundary dominated flow (after four plus years) due to the ultra low permeability of the reservoir and complex fractures created from hydraulic stimulation. Figure 9 presents Horn River typecurves of average, P10 and P90 horizontal well performance. After 40 months (based on a sample size of approximately 100 wells, anomalies are an artifact of fluctuating well count), the average well has produced 76 10^6m^3 (2.7 BCF), with 90 per cent of the wells (P90) producing more than 20 10^6m^3 (0.7 BCF) and 10 per cent of the wells (P10) producing more than 141 10^6m^3 (5.0 BCF).

Reserves Evaluation Methodology

Gas reserves for the HRB have been calculated volumetrically since initial evaluation was conducted by the Commission in 2010. Pool designation areas have expanded since this time and currently represent approximately 30 per cent of the total prospective area. Proved plus probable reserves (incorporating undeveloped PUDs) are calculated using a conservative 25 per cent recovery factor for shale gas. Future revisions, incorporating decline analysis and statistical techniques used for Montney reserves, will occur upon reaching a larger data set of drilling and production.

Figure 9: Horn River Horizontal Well Typecurves



Liard Basin - Unconventional Shale Gas Play

The Liard Basin is a new unconventional resource in northeast B.C., with a preliminary EUR of 2,933 10^6m^3 (104 BCF) booked in 2012, based on production from three existing wells, two vertical and one horizontal. With promising initial results and a prospective area of one million hectares (Figure 10), the Liard Basin is a potentially large future gas producing region.

A major structural feature, the Bovie fault zone, separates the Liard from the HRB. The Liard Basin has more than five km of sedimentary rocks preserved including thick, organic shales within the upper and lower Devonian Besa River strata. Initial reservoir pressure within the upper Besa River shales is 77.3 MPa, nearly double the expected pressure of a normally pressured reservoir at that depth. Such over-pressure is indicative of a sealed hydrocarbon system, with encouraging implications for well productivity and resource density. Reservoir pressures in the adjacent HRB range from 20 to 53 MPa; significantly lower than those seen in the Liard to date (see Figure 11 – Pressure versus Temperature graph).

Figure 10: Northeast Shale Basins - Liard, Horn River and Cordova Embayment

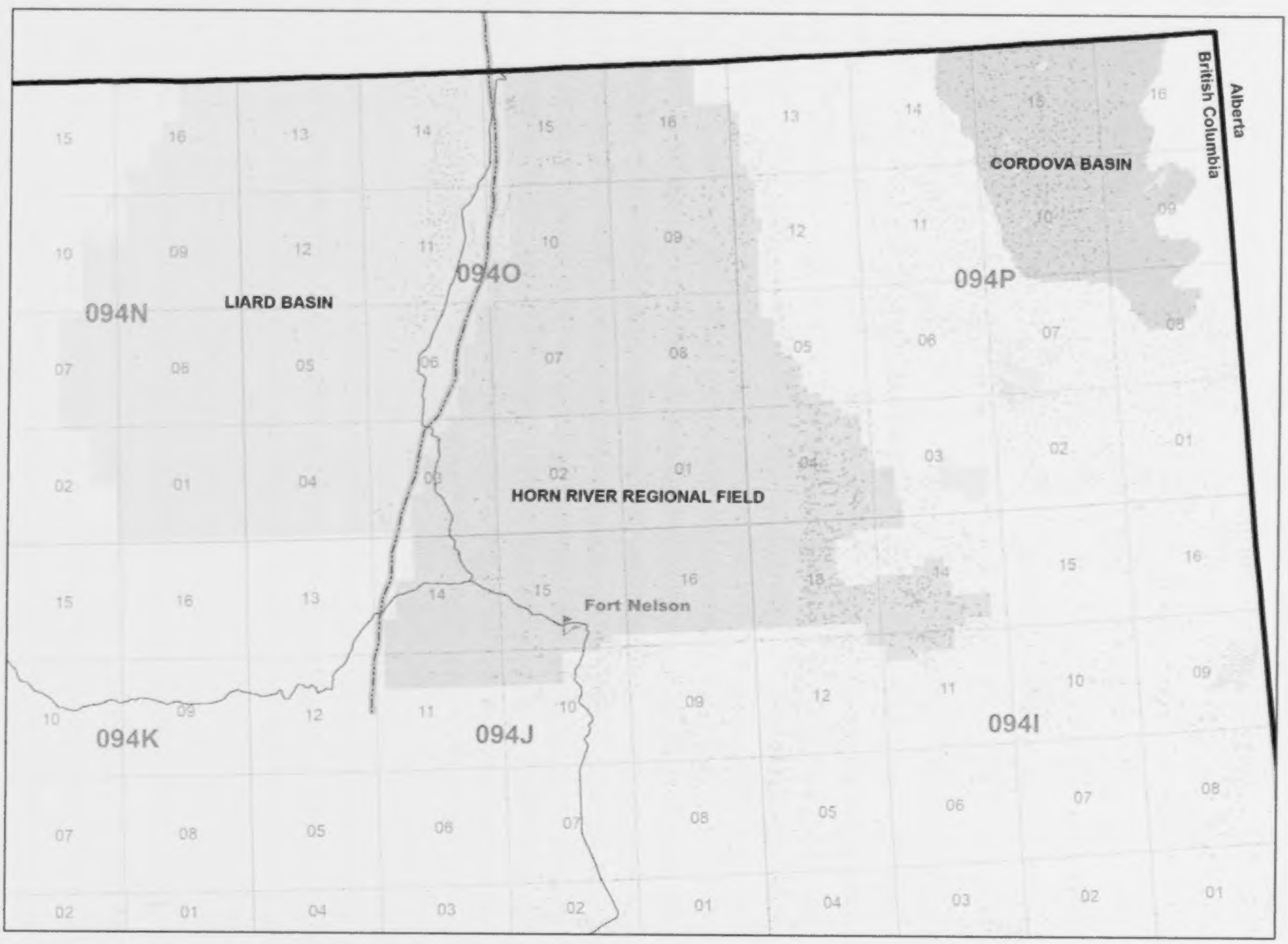
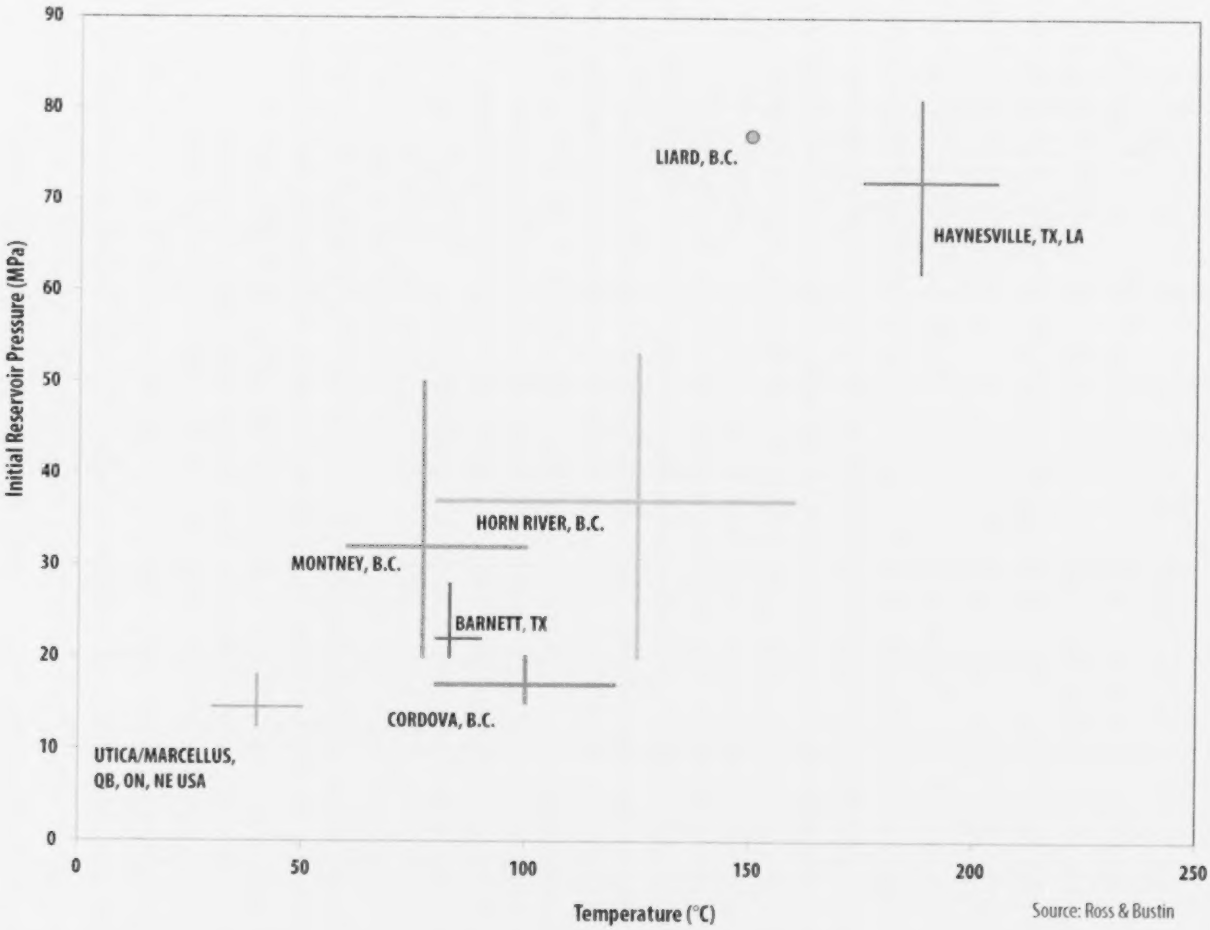


Figure 11: Pressure versus Temperature - Liard versus NA Shale Basins



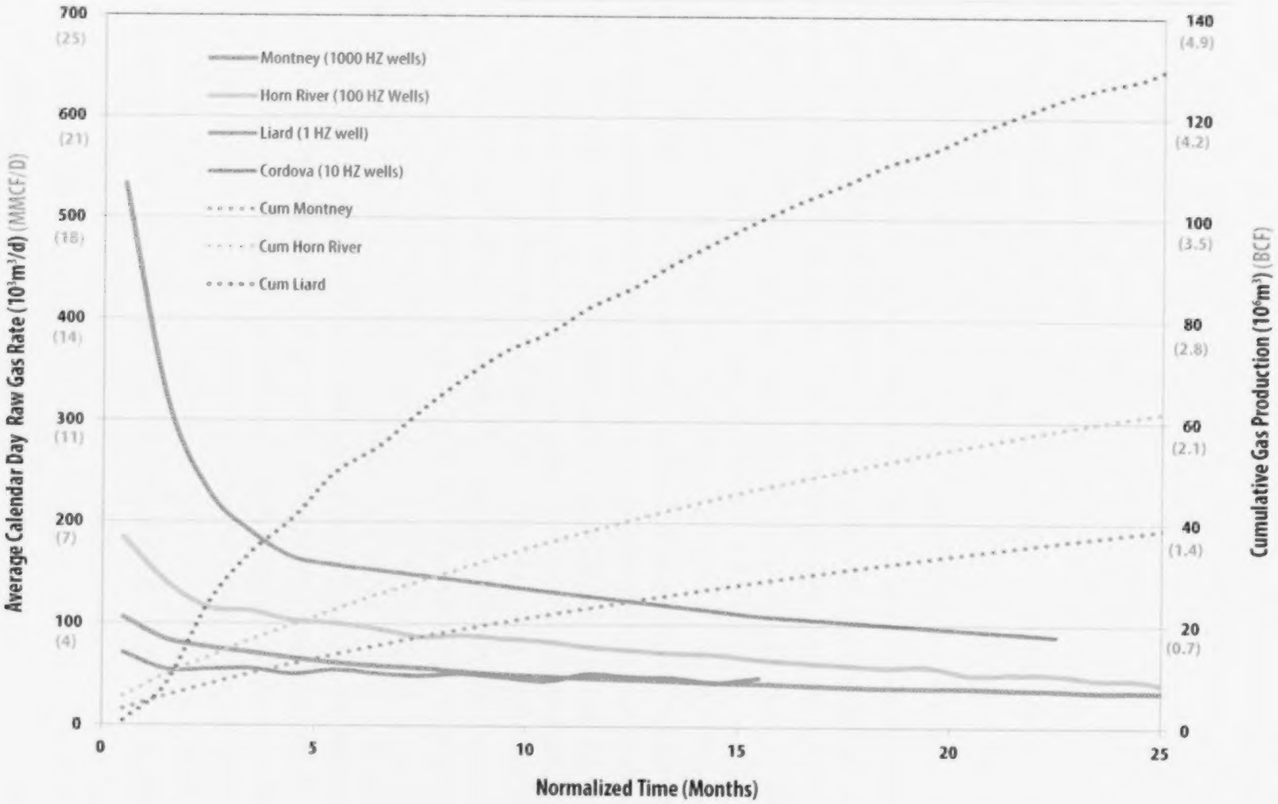
Source: Ross & Bustin

Gas analysis from the three Liard wells drilled to date indicates CO_2 content of approximately seven per cent, lower than the 12 per cent observed in the western portions of the Horn River. Preservation of the relatively high methane content of the gas may be due to a lower than expected temperature gradient. Although much deeper than even the deepest portions of the HRB, the temperatures at the upper Besa River level are similar to the maximum temperatures seen in the HRB.

The shale gas potential of the Besa River formation was tested with the drilling and stimulation of two vertical wells and one horizontal well in 2009-2010, in an area previously devoid of deep well tests. Test results (seven MMCF/D vertical well and 30 MMCF/D HZ well) and production are very promising and among the best of any shale gas play in North America. Using decline analysis, the Commission assigned approximately eight BCF/well to the vertical wells and 19 BCF to the horizontal well. With six stimulations over a 900 m horizontal section, (1,500 T sand; 23,000 m^3 water), the Commission forecasts an EUR of over three BCF/frac for the horizontal Liard well, compared with one BCF/frac for the Horn River and 0.5 BCF/frac for the Montney, on average.

The promising results of the first horizontal Liard well are shown in Figure 12 in relation to the average horizontal type well in the Montney and Horn River. Peak initial rate from the Liard well is three times that of the average Horn River well and five times that of the average Montney well. Cumulative gas production from the Liard well after two years (126 10^6m^3, 4.4 BCF) is double that of the average Horn River well (10^6m^3, 2.1 BCF) and more than triple that of the average Montney well (38 10^6m^3, 1.3 BCF).

Figure 12: Liard Single Horizontal Well Performance versus Montney and Horn River Average Well Typecurves



Cordova Embayment - Unconventional Shale Gas Play

The Cordova Embayment, similar to the HRB, is an unconventional shale play targeting dry gas from mid-Devonian aged shales of the Muskwa, Otter Park and Evie Formations. Situated east of the HRB, the Cordova Embayment is located approximately 130 km northeast of Fort Nelson, covers approximately 2,700 km^2 and is bordered by the time equivalent Devonian Carbonate Barrier Complex (Figure 11). Stratigraphically, the organic rich siliciclastic Muskwa, Otter Park and Evie shales of the Horn River group are overlain by the Fort Simpson shales and underlain by the Keg River platform carbonates.

As with the HRB, the Cordova Embayment mapping combines the Muskwa and Otter Park formations into one interval, with the Evie formation evaluated and mapped separately. Although not yet explored to the extent of the HRB, and having a thinner and more normally pressured reservoir, drilling to date indicates prospectivity within each of the shale intervals over significant portions of the Embayment. The area contains a large number of wells and infrastructure for development of the overlying Helmet field Jean Marie formation.

The location of the Cordova Embayment, in relation to the Horn River and Liard shale basins, is shown in Figure 10. A general range of reservoir parameters is provided in Table 7.

The average CO_2 content in the Cordova Embayment is eight per cent, slightly lower than the 10-12 per cent present in the HRB. There are trace amounts of H_2S (<0.6 ppm).

Table 7: Cordova Shale Reservoir Parameters

Reservoir Data	
Depth Range	1,500 – 2,300 m
Gross Thickness	70 – 120 m
TOC Range	2 – 5%
Porosity	3 – 6%
Water Saturation	25%
Pressure	15 – 20 MPa
Pressure Regime	Normal
Temperature	80 – 120° C

Table 8: Cordova Shale Drilling and Completions (2010-2012)

Drilling Data	
Wells per pad	Up to 9
HZ length	Up to 2,400 m, average ~2,100 m
Wellbore	80% Cased, 20% Open hole
Completion Data	
Completion method	80% Perf and plug / 20% Ball and seat
Fracture	Slickwater
Number of stages	Up to 22, average 17
Pump rate	8 – 16 m^3 per min
Water per well	Average 43,000 m^3
Sand per well	Average 4,100 T

Development History

The first gas wells in the Cordova Embayment targeting shale were rig released in 2008. As of December 31, 2012, 21 horizontal wells and five vertical wells have been drilled. The majority of the drilling to date occurred in 2011 (14 wells), with five wells drilled in 2012. Annual production for 2012 was 215 10^6m^3 (7.6 BCF), with 20 producing wells at year end.

Drilling and Completions

The completions approach in Cordova was comparable to the Horn River. The average values from the 19 horizontal wells completed in 2010-2012 are summarized in Table 8. The first two horizontal wells drilled in 2008 and 2009 had smaller completions. The average horizontal well has a 2,100 m horizontal cased hole lateral and was stimulated with 17 slickwater fracture stages using 43,000 m^3 of water and 4,100 T of sand. N_2 gas as an energizer was employed in two wells.

Production

The average horizontal type well for Cordova is shown in comparison to the Montney, Horn River and Liard in Figure 12. Although initial rates are lower than the neighboring Muskwa-Otter Park and Evie shales of the HRB to the west (despite similar completion technique), the decline appears to be more stable. More drilling and production is required to substantiate the Cordova type well.

Reserves Evaluation Methodology

Remaining reserves of 844 10^6m^3 (30 BCF) were calculated volumetrically with a 25 per cent RF, for the area proven by drilling (2,622 ha, 10 GSUs, less than one per cent of Basin). Similar to the Horn River, future reserve revisions, incorporating decline analysis and statistical techniques used for Montney reserves, will occur upon reaching a larger data set of drilling and production. Reserves values are provided in Appendix C within the Helmet field Muskwa-Otter Park "A" and Evie "A" pools, as a separate regional field has not yet been designated.

B. Oil Reserves

Oil reserves increased five per cent in 2012, for a total of 19.1 10^6m^3 remaining oil reserves as of December 31, 2012. The majority of this increase came from the introduction of Montney oil reserves in the Heritage – Montney "A" oil pool. Annual provincial oil production was 1.2 10^6m^3, up six per cent from 2011. The year 2012 saw 41 new oil production wells, with 10 injector wells drilled for pressure maintenance.

Historical oil reserves, drilling, production and R/P ratio are plotted in Figure 13. Oil production reached a peak of 2.5 10^3m^3 per year in 1998 and was then on the decline until 2010, when it began to stabilize with continued horizontal drilling and waterflood pressure maintenance. The R/P ratio has been steady since 2009, with approximately 15 years of reserve life booked. Oil well drilling has fluctuated in recent years, from a low in 2008 (13 wells), to a high in 2011 of 52 wells, primarily horizontal drilling in the Hay River – Bluesky "A" pool.

The distribution of remaining oil reserves by field is shown in Figure 14. The Boundary Lake – Boundary Lake "A" pool and the Hay River – Bluesky "A" pool are the largest contributing pools to overall remaining oil reserves in the province, with the newly discovered Heritage – Montney "A" pool contributing three per cent to total reserves in its early stages of development.

Figure 13: Historical Oil Development in B.C.

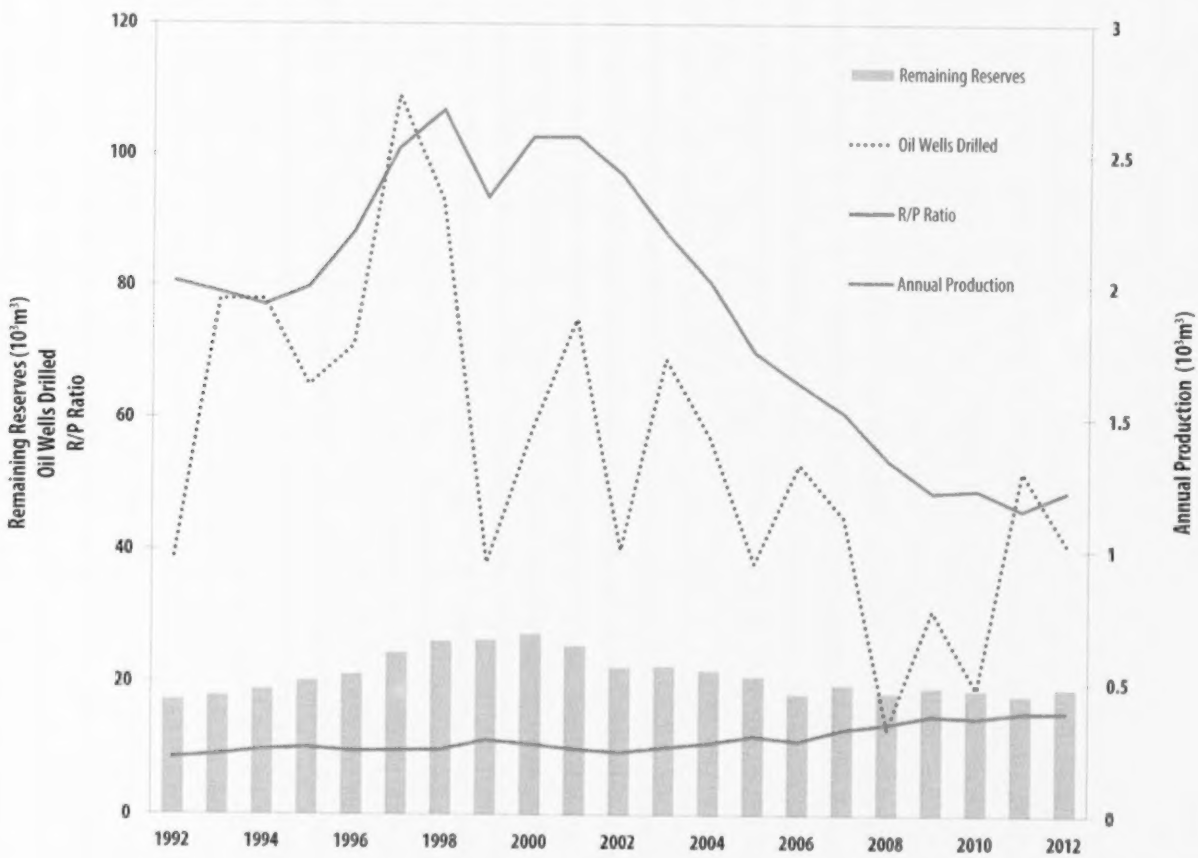
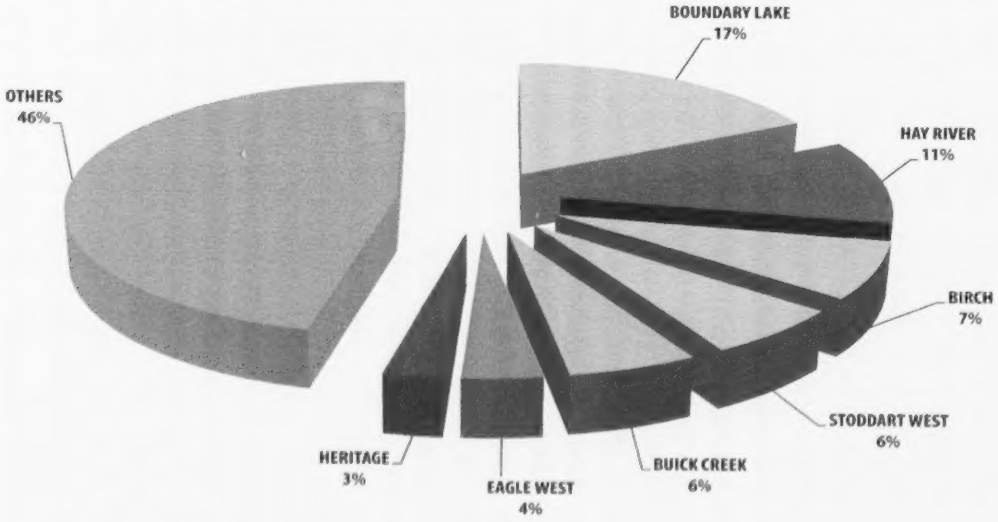


Figure 14: Remaining Oil Reserves by Field



Half of the remaining oil reserves in B.C. come from pools with secondary recovery pressure maintenance schemes, predominantly waterfloods. A summary of the EUR and remaining reserves for each of the 49 pools under waterflood is provided in Table A-5 in Appendix A. Gas injection recovery schemes account for one per cent of remaining oil reserves and occur in six oil pools (see Table A-6 in Appendix A). Many of these pressure maintenance schemes have been in operation for over 25 years and are potential candidates for tertiary recovery.

Heritage - Montney "A" Oil

A significant addition to oil reserves is the Heritage Montney "A" oil pool in the central Tower area of the Montney Play Trend (see Figure 6b). The regionally extensive Triassic Montney formation trends from dry to rich gas, with a less mature hydrocarbon oil pool in an area of lower pressure and shallower depth. Given the potential of the resource and lack of analogous reservoirs, the Commission is focused on determining best production practice for maximizing recovery.

There are 10 existing Montney oil wells with a forecasted average EUR of 18.7 10^3m^3 per well, (118 MBBL/well). Following guidelines from SPEE Monograph 3, 20 PUDs were booked with an aggregated P90 of 17 10^3m^3 per well (107 MBBL/well). The total EUR assigned to the new Heritage Montney "A" oil leg is 526.6 10^3m^3 (3,312 MBBL), which represents a two per cent RF of the original oil in place (OOIP) of 26,329 10^3m^3 (165,591 MBBL). Reservoir parameters are provided in Table 9.

Table 9: Heritage Montney "A" Oil Pool Reservoir Parameters

Reservoir Data	
Depth Range	1,800 – 2,000 m
Initial Pressure	23 MPa
Pressure Regime	Normal – Overpressure (10-12 kPa/m)
Temperature	65 – 70° C
API Gravity	45°
Solution GOR	200

C. Condensate and NGL Reserves

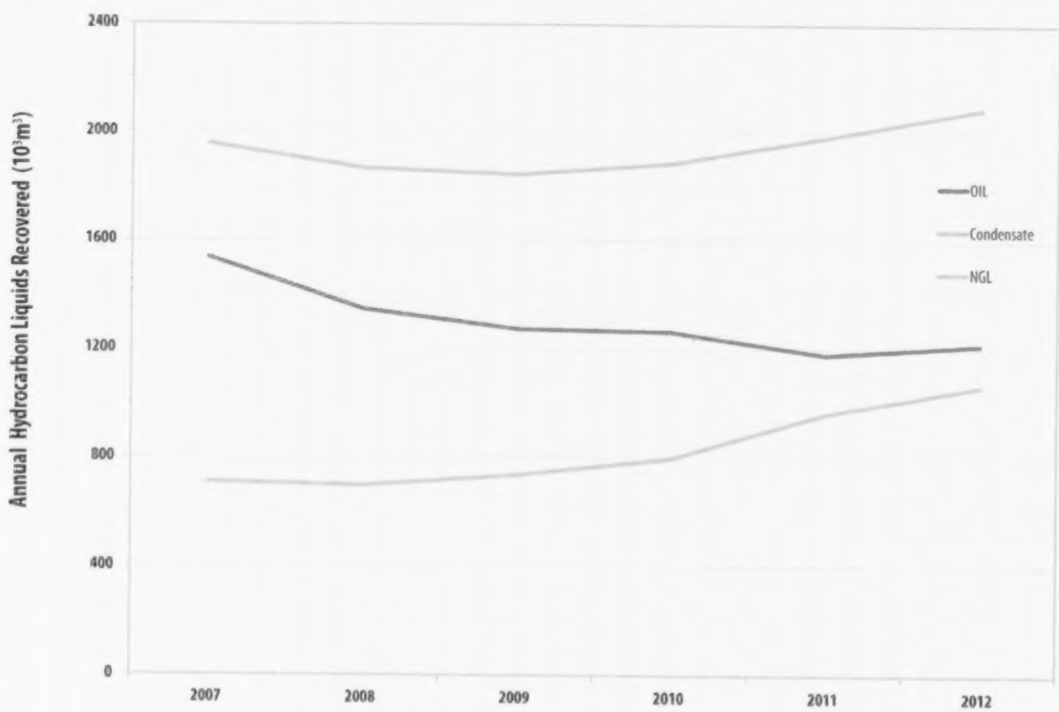
Condensate and natural gas liquids (NGLs) produced in association with natural gas are on the rise in B.C., predominately due to the development of rich gas and liquids rich portions of the Montney Play Trend (see Figure 6b). Condensate, heavy pentanes plus (C_{5+}) in the gas stream, may be separated at the wellhead (field) or extracted at a processing point (plant). NGLs include ethane (C_2), propane (C_3) and butane (C_4) components in the gas stream that are separated at the plant for sales.

Condensate and NGL reserves increased for the fourth consecutive year (See Table 1, in the Summary section). Figure 15 compares annual volumes of condensate, NGL, and oil. Oil production has been fairly stable since 2010 while both condensate and NGL recovery are on the rise. B.C.'s annual condensate volume, comparable in value to oil, is up 50 per cent since 2007.

Condensate and NGL reserves are currently calculated based on the yield achieved at the plant to which the associated raw gas reserves are delivered. The Commission is conducting a comprehensive review of condensate and NGL reserves, given the increased significance in recent years.

The associated free condensate and plant recovered C_{5+} and natural gas liquids have provided an economic upside for many companies producing natural gas. Fortunately, the Montney trend has areas where significant condensate gas ratios are achieved and seem to be sustained over time, fostering continued development programs. Similar to oil, the Commission is working to clarify the relationship of liquids recovery to individual wells, to allow characterization and a data history for development of best production practices to maximize recoveries.

Figure 15: Annual Oil, Condensate and NGL Volumes



D. Sulphur Reserves

Sulphur is recovered from natural gas containing H_2S. Sulphur reserves are calculated based on the yield achieved at the plant to which the associated raw gas reserves are delivered. There are 15.7 10^6m^3 of sulphur reserves remaining, a 15 per cent increase from 2011 results. A map of the distribution of H_2S by field can be found on the Commission website.

Of significance for activity focus on the Montney and Horn River, they contain little to no H_2S (Montney - less than 0.3 per cent, Horn River - less than 0.1 per cent) and are expected to have minimal effect on future sulphur reserves.

Definitions

SI Units

British Columbia's reserves of oil, natural gas liquids and sulphur are presented in the International System of Units (SI). Both SI units and the Imperial equivalent units are used through the report. Conversion factors used in calculating the Imperial equivalents are listed below.

1 cubic metre of gas (101.325 kilopascals and 15° Celsius)	=	35.315 cubic feet of gas (14.73 psia and 60° Fahrenheit)
1 cubic metre of ethane (equilibrium pressure and 15° Celsius)	=	6.330 0 Canadian barrels of ethane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of propane (equilibrium pressure and 15° Celsius)	=	6.300 0 Canadian barrels of propane (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of butanes (equilibrium pressure and 15° Celsius)	=	6.296 8 Canadian barrels of butanes (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of oil or pentanes plus (equilibrium pressure and 15° Celsius)	=	6.292 9 Canadian barrels of oil or pentanes plus (equilibrium pressure and 60° Fahrenheit)
1 cubic metre of water (equilibrium pressure and 15° Celsius)	=	6.290 1 Canadian barrels of water (equilibrium pressure and 60° Fahrenheit)
1 tonne	=	0.984 206 4 (U.K.) long tons (2,240 pounds)
1 tonne	=	1.102 311 short tons (2,000 pounds)
1 kilojoule	=	0.948 213 3 British thermal units (Btu as defined in the federal Gas Inspection Act [60°- 61° Fahrenheit])

Aggregated P90
The 90 per cent probability of a distribution formed as a result of an aggregation of outcomes.

Area
The area used to determine the adjusted bulk rock volume of the oil, or gas-bearing reservoir, usually the area of the zero isopach or the assigned area of a pool or deposit.

Butane
(C_4H_{10}) An organic compound found in natural gas. Reported volumes may contain some propane or pentanes plus.

COGEH
Canadian Oil and Gas Evaluations Handbook. First published in 2002 by the Calgary Chapter of the Society of Petroleum Evaluation Engineers (SPEE) to act as a standard for the evaluation of oil and gas properties.

Compressibility Factor
A correction factor for non-ideal gas determined for gas from a pool at its initial reservoir pressure and temperature and, where necessary, including factors to correct for acid gases.

Condensate
A mixture mainly of pentanes and heavier hydrocarbons (C_{5+}) that may be contaminated with sulphur compounds that is recovered at a well or facility from an underground reservoir and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured.

Density
The mass or amount of matter per unit volume.

Density, Relative (Raw Gas)
The density, relative to air, of raw gas upon discovery, determined by an analysis of a gas sample representative of a pool under atmospheric conditions.

Discovery Year
The year in which the well that discovered the oil or gas pool finished drilling.

Estimated Ultimate Recovery (EUR)
Total volume of oil or gas recoverable under current technology and present and anticipated economic conditions. This is also referred to as Initial Reserves in the detailed reserves tables in Appendix C.

Formation Volume Factor
The volume occupied by one cubic metre of oil and dissolved gas at reservoir pressure and temperature, divided by the volume occupied by the oil measured at standard conditions.

Gas (Non-associated)
Gas that is not in communication with an accumulation of liquid hydrocarbons at initial reservoir conditions.

Gas Cap (Associated)
Gas in a free state in communication with crude oil, under initial reservoir conditions.

Gas (Solution)
Gas that is dissolved in oil under reservoir conditions and evolves as a result of pressure and temperature changes.

Gas (Raw)
A mixture containing methane, other paraffinic hydrocarbons, nitrogen, carbon dioxide, hydrogen sulphide, helium, and minor impurities, or some of them, which is recovered or is recoverable at a well from an underground reservoir and which is gaseous at the conditions under which its volume is measured or estimated.

Gas (Marketable)
A mixture mainly of methane originating from raw gas, if necessary, through the processing of the raw gas for the removal or partial removal of some constituents, and which meets specifications for use as a domestic, commercial, or industrial fuel or as an industrial raw material.

Gas-Oil Ratio (Initial Solution)
The volume of gas (in thousand cubic metres, measured under standard conditions) contained in one stock-tank cubic metre of oil under initial reservoir conditions.

Gross Heating Value (of dry gas)
The heat liberated by burning moisture-free gas at standard conditions and condensing the water vapour to a liquid state.

Initial Reserves
Established reserves prior to the deduction of any production. Also referred to as EUR.

Liquid Petroleum Gases (LPG)
A hydrocarbon mixture comprised primarily of propane and butanes. Some ethanes may be present. Also referred to as natural gas liquids (NGLs).

Mean Formation Depth
The approximate average depth below kelly bushing of the mid-point of an oil or gas productive zone for the wells in a pool.

Methane
In addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium or carbon dioxide.

Natural Gas Liquids
Ethane, propane, butanes, or pentanes plus, or a combination of them, obtained from the processing of raw gas or condensate.

Oil
A mixture mainly of pentanes and heavier hydrocarbons that may be contaminated with sulphur compounds, that is recovered or is recoverable at a well from an underground reservoir, and that is liquid at the conditions under which its volume is measured or estimated, and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas or condensate.

Original Gas and Original Oil in Place
The volume of oil, or raw natural gas estimated to exist originally in naturally occurring accumulations, prior to production.

Pay Thickness (Average)
The bulk rock volume of a reservoir of oil or gas, divided by its area.

Pentanes Plus
A mixture mainly of pentanes and heavier hydrocarbons, (which may contain some butane), that is obtained from the processing of raw gas, condensate, or oil.

Pool
A natural underground reservoir containing or appearing to contain an accumulation of liquid hydrocarbons or gas or both separated or appearing to be separated from any other such accumulation.

Porosity
The effective pore space of the rock volume determined from core analysis and well log data, measured as a fraction of rock volume.

Pressure (Initial)
The reservoir pressure at the reference elevation of a pool upon discovery.

Probabilistic Aggregation
The adding of individual well outcomes to create an overall expected reserve outcome.

Project/Units
A scheme by which a pool or part of a pool is produced by a method approved by the Commission.

Propane
(C_3H_8) An organic compound found in natural gas. Reported volumes may contain some ethane or butane.

Proved Plus Probable Reserves
Proved plus probable reserves are estimates of hydrocarbon quantities to be recovered. There is at least a 50 per cent probability that the actual quantities recovered will equal or exceed the estimated proved plus probable reserves.

PUD (Proved Undeveloped)
Proved undeveloped reserves that are assigned to undrilled well locations that are interpreted from geological, geophysical, and/or analogous production, with reasonable certainty to exist.

P10
There is a 10 per cent probability (P10) that the quantities actually recovered will equal or exceed this value.

P50
There is a 50 per cent probability (P50) that the quantities actually recovered will equal or exceed this value.

P90
There is a 90 per cent probability (P90) that the quantities actually recovered will equal or exceed this value.

Recovery
Recovery of oil, gas or natural gas liquids by natural depletion processes or by the implementation of an artificially improved depletion process over a part or the whole of a pool, measured as a volume or a fraction of the in-place hydrocarbons so recovered.

Remaining Reserves
Initial established reserves (EUR) less cumulative production.

Reserves
Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub classified based on development and production status (from COGEH).

Resource
Resources are those quantities of hydrocarbons estimated to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development (adapted from COGEH).

Saturation (Water)
The fraction of pore space in the reservoir rock occupied by water upon discovery.

SPEE Monograph 3
An established guideline published by the Society of Petroleum Evaluations Engineers (2010) which discusses evaluation of undeveloped reserves in resource plays.

Surface Loss
A summation of the fractions of recoverable gas that are removed as acid gas and liquid hydrocarbons, used as lease or plant fuel, or flared.

Temperature
The initial reservoir temperature upon discovery at the reference elevation of a pool.

Unconnected Reserves
Gas reserves which have not been tied-in to gathering facilities and therefore do not contribute to the provincial supply without further investment.

Zone
Any stratum or any sequence of strata that is designated by the Commission as a zone.

Appendix A

2012 Hydrocarbon Reserves (SI Units)

Table A-1: Established Hydrocarbon Reserves (SI Units) by December 31, 2012

	Oil (10^3m^3)	Raw Gas (10^6m^3)
Initial Reserves, Current Estimate	134,600	2,014,054
Drilling 2012	537	1,646
Revisions 2012	1,614	202,809
Production 2012	1,222	40,482
Cumulative Production Dec. 31, 2012	115,492	875,580
Remaining Reserves Estimate Dec. 31, 2012	19,108	1,138,474

Table A-2: Established Hydrocarbon Reserves (Imperial Units) by December 31, 2012

	Oil (MSTB)	Raw Gas (BSF)
Initial Reserves, Current Estimate	847,024	71,126
Drilling 2012	3,378	58
Revisions 2012	10,156	7,162
Production 2012	7,690	1,430
Cumulative Production Dec. 31, 2012	726,780	30,921
Remaining Reserves Estimate Dec. 31, 2012	120,245	40,205

Table A-3: Historical Record of Raw Gas Reserves

Year	Estimated Ultimate Recovery 10⁶m³	Yearly Drilling 10⁶m³	Yearly Revisions 10⁶m³	Yearly Other 10⁶m³	Production in Year 10⁶m³	Cumulative Production at Year-End 10⁶m³	Remaining Reserves at Year-End 10⁶m³
1977	376,960	18,119	14,107		11,039	143,958	233,002
1978	399,535	21,190	1,386		9,943	153,900	245,635
1979	424,805	26,142	872		11,394	165,294	259,511
1980	462,596	28,909	8,882		8,968	174,262	288,334
1981	478,689	13,842	2,251		8,293	182,555	296,134
1982	488,316	7,765	1,862		7,995	190,550	297,766
1983	490,733	2,550	133		7,845	198,395	292,338
1984	496,703	1,798	4,172		8,264	206,659	290,044
1985	505,233	2,707	5,823		8,799	215,458	289,775
1986	501,468	4,822	8,463		8,506	223,964	277,628
1987	497,466	1,986	5,940		9,810	233,794	263,777
1988	500,738	6,083	1,661		10,275	244,249	256,483
1989	513,662	12,193	2		13,276	257,862	255,782
1990	547,058	27,683	5,888		13,226	271,344	275,685
1991	574,575	24,708	3,812		15,162	285,965	288,582
1992	591,356	6,377	10,404		16,510	302,916	288,408
1993	617,379	22,901	3,122		18,202	321,090	296,246
1994	635,774	22,004	3,301		19,069	339,861	295,885
1995	657,931	21,065	1,051		21,157	361,106	296,825
1996	677,769	16,083	3,852		21,435	382,332	295,437
1997	688,202	12,835	2,394		22,811	405,157	283,045
1998	712,677	9,957	14,502		23,375	428,822	283,855
1999	743,816	13,279	17,824		23,566	453,000	290,816
2000	772,221	13,832	14,571		23,894	477,381	294,800
2001	811,146	7,199	31,690		26,463	504,620	306,526
2002	843,612	19,004	13,462		28,348	533,548	310,064
2003	889,488	19,317	26,282		26,639	562,560	326,928
2004	973,771	6,412	65,149	12,897	26,430	584,033	389,738
2005	1,065,288	8,974	63,268	19,104	27,854	620,696	444,592
2006	1,114,562	15,356	33,912		28,056	652,137	462,425
2007	1,172,136	21,468	36,109		29,362	689,209	482,927
2008	1,328,729	6,559	150,167		30,346	722,769	605,280
2009	1,415,172	30,331	56,133		30,846	757,291	657,881
2010	1,724,769	275,942	33,691		33,202	792,798	931,971
2011	1,809,591	7,909	76,934		40,519	834,715	974,876
2012	2,014,054	1,646	202,809		40,482	875,580	1,138,474

Table A-4: Historical Record of Oil Reserves

Year	Estimated Ultimate Recovery	Yearly Drilling	Yearly Revisions	Yearly Other	Production in Year	Cumulative Production at Year-End	Remaining Reserves at Year-End
	10^3m^3	10^3m^3	10^3m^3	10^3m^3	10^3m^3	10^3m^3	10^3m^3
1977	72,841	4,159	84		2,201	46,318	26,523
1978	77,826	2,650	2,376		2,004	48,280	29,546
1979	78,882	427	629		2,140	50,397	28,485
1980	80,043	234	927		2,002	52,399	27,644
1981	79,968	143	218		2,060	54,459	25,509
1982	80,760	126	666		2,095	56,554	24,206
1983	82,149	661	727		2,079	58,634	23,515
1984	79,551	781	3,378		2,113	60,747	18,805
1985	82,887	1,767	1,569		1,944	62,691	20,196
1986	83,501	456	144		2,010	64,701	18,786
1987	84,201	631	68		2,084	66,793	17,361
1988	85,839	1,238	50		1,937	68,759	16,623
1989	89,899	2,306	2,402		1,978	70,737	19,129
1990	90,650	569	181		1,954	72,714	17,823
1991	91,606	233	630		1,974	74,689	16,911
1992	94,030	823	1,596		2,017	76,750	17,273
1993	96,663	803	1,830		1,976	78,726	17,925
1994	99,619	1,477	1,482		1,929	80,664	18,956
1995	102,823	2,887	290		1,997	82,658	20,167
1996	106,009	1,306	1,878		2,205	84,856	21,153
1997	110,765	3,199	1,561		2,525	87,401	23,364
1998	116,294	815	4,717		2,670	90,105	26,189
1999	118,840	345	2,201		2,338	92,453	26,388
2000	122,363	504	3,018		2,568	95,031	27,357
2001	123,048	106	582		2,569	97,591	25,478
2002	122,245	427	1,233		2,426	99,977	22,313
2003	124,660	424	1,990		2,203	102,234	22,426
2004	125,953	154	947	188	2,015	104,104	21,873
2005	126,941	247	636	110	1,750	106,086	20,857
2006	125,845	222	1,322		1,631	107,603	18,244
2007	128,971	266	2,859		1,520	109,283	19,692
2008	129,117	162	25		1,341	110,632	18,485
2009	131,172	289	1,766		1,282	111,924	19,252
2010	131,840	643	28		1,270	113,197	18,653
2011	132,414	99	475		1,154	114,253	18,161
2012	134,600	537	1,614		1,222	115,492	19,108

Table A-5: Oil Pools Under Waterflood

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Beatton River	Halfway A	3,430	47	1,617	1,617	0
Beatton River	Halfway G	1,568	30	470	424	46
Beavertail	Halfway B	503	18	91	86	5
Beavertail	Halfway H	909	20	182	164	18
Birch	Baldonnel C	4,070	50	2,035	629	1,406
Boundary Lake	Boundary Lake A	81,597	47	38,099	35,505	2,594
Bubbles North	Coplin A	144	40	58	39	19
Bulrush	Halfway C	96	4	4	4	0
Crush	Halfway A	1,579	32	510	503	7
Crush	Halfway B	149	38	56	50	6
Currant	Halfway A	793	53	419	419	0
Currant	Halfway D	122	20	24	8	16
Desan	Pekisko	5,223	15	784	683	101
Eagle	Belloy-Kiskatinaw	6,929	40	2,772	2,530	242
Eagle West	Belloy A	20,337	32	6,569	6,201	368
Elm	Gething B	1,773	8	133	127	6
Halfway	Debolt A	950	10	95	95	0
Hay River	Bluesky A	31,033	20	6,207	4,182	2,025
Inga	Inga A	19,829	37	7,266	6,868	398
Lapp	Halfway C	1,015	45	457	436	21
Lapp	Halfway D	369	45	166	155	11
Milligan Creek	Halfway A	14,002	53	7,440	7,385	55
Muskrat	Boundary Lake A	1,003	40	401	310	91
Muskrat	Lower Halfway A	465	25	116	106	10
Oak	Cecil B	424	30	127	98	29
Oak	Cecil C	908	60	545	337	208
Oak	Cecil E	1,314	48	631	595	36
Oak	Cecil I	1,335	20	267	227	40
Owl	Cecil A	785	45	353	316	37
Peejay	Halfway	25,474	42	10,578	10,437	141
Peejay West	Halfway A	1,050	50	525	442	83
Red Creek	Doig C	4,359	5	218	148	70
Rigel	Cecil B	1,225	52	637	572	65
Rigel	Cecil G	953	45	429	415	14
Rigel	Cecil H	1,821	50	910	870	40
Rigel	Cecil I	2,146	40	858	750	108
Rigel	Halfway C	1,491	33	496	488	8
Rigel	Halfway Z	104	20	21	7	14

Table A-5: Oil Pools Under Waterflood (continued)

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Squirrel	North Pine C	1,376	30	413	409	4
Stoddart	North Pine G	390	40	156	66	90
Stoddart West	Bear Flat D	442	35	155	152	3
Stoddart West	Belloy C	5,784	25	1,446	1,329	117
Stoddart West	North Pine D	94	40	38	21	17
Sunset Prairie	Cecil A	882	40	353	329	24
Sunset Prairie	Cecil C	420	35	147	120	27
Sunset Prairie	Cecil D	380	40	152	5	147
Two Rivers	Siphon A	1,370	20	274	231	43
Weasel	Halfway	5,463	63	3,439	3,326	113
Wildmint	Halfway A	2,878	54	1,554	1,539	15
Total				100,693		8,938
% of Total British Columbia Reserves				75		47

Table A-6: Oil Pools Under Gas Injection

FIELD	POOL	OOIP (10^3m^3)	RF %	EUR (10^3m^3)	Cum Oil (10^3m^3)	RR (10^3m^3)
Brassey	Artex A	94	16	15	14	1
Brassey	Artex G	353	42	150	149	1
Bulrush	Halfway A	820	45	369	314	55
Cecil Lake	Cecil D	893	40	357	325	32
Rigel	Halfway H	703	15	105	90	15
Stoddart West	Belloy C	1,701	25	425	376	49
Total				1,421		153
% of Total British Columbia Reserves				1		1

Appendix B

Unconventional Reserves Evaluation Method

The fundamental shift in focus to unconventional resources has necessitated the Commission adopt an appropriate approach to reserves evaluation. Conventional reserve evaluation techniques tend to overestimate recoverable reserves when they are applied to large scale resource plays, due to the lack historical data to determine recovery factors. Wells produce from semi-independent pressure regimes within an area of stimulated rock volume. Once production commences the length of shut-in time to acquire a reasonable reservoir pressure is excessive, removing material balance as an evaluation technique.

Therefore, the Commission has adopted the guidelines outlined in the Society of Petroleum Evaluation Engineers (SPEE) Monograph 3, "Guidelines for the Practical Evaluation of Undeveloped Reserves in Resource Plays" as a primary methodology. Significant efforts have been made to ensure evaluation methods are accurate, consistent and will grow in proportion to the level of development of the resource.

The Monograph 3 methodology was applied to each Montney gas pool, as well as the Heritage – Montney "A" oil pool. Analysis method is dependent on the current stage of development. The following steps were taken to determine the Estimated Ultimate Recovery (EUR) for each pool;

1. EUR forecast utilizing production data for every Montney gas well. A total of 1,430 wells were individually evaluated.
   i. Two different forecasting models were used to evaluate the wells; Modified Arps, (with two segments for transient flow and boundary dominated flow (BDF)), and Stretched Exponential when sufficient data to provide a reasonable fit. For Modified Arps, the decline parameters used in most cases were: decline exponent (b) of 2.0 for transient flow and 0.5 for BDF, six years to the time of BDF, 10 per cent terminal decline for BDF and an abandonment rate of 100 MCF/d. The initial nominal decline was adjusted manually to best fit the initial data.
   ii. For rate restricted wells with artificially shallow declines, a representative Modified Arps curve was applied to the end of the data to estimate the future decline.
2. Horizontal and vertical wells were segregated and grouped by pool to determine the statistical attributes of each data set. Information was attained for each data set: Best fit distribution, P90, P50, P10 and mean.

3. Determine the phase of resource development referencing Tables in Monograph 3 with P90/P10 ratios and well count.
   i. Regional Northern Montney pools are in the "Early" stage of development.
   ii. Heritage Montney pool is in the "Mature" stage of development.

4. Determine the number of PUDs to be assigned.
   i. Northern Montney "early phase" pools simply receive two PUDs for every existing well.
   ii. Heritage Montney "mature phase" required a more sophisticated approach when determining the number of PUDs. Monograph 3 recommends a full statistical approach to determine proved area and well density, however, due to the extremely large area a slightly more simplified approach was used, which can be easily updated and will properly reflect the level of development in the area.
      a. Development of a function to determine the well density per GSU. See Appendix B, Figure B-3.
      b. Using the recommended minimum sample size of 130 for the P10/P90 ratio, a well density of six wells per "proved" GSU (containing a producing well) was determined for the Heritage Montney pool. Multiplying 378 proved GSUs (24 per cent of total field) with a well density of six wells per GSU and deducting the existing wells provided the number of PUDs.

5. Monte Carlo simulations were run for each prospective outcome using the defined distributions of each data set. The outcomes were aggregated to produce representative probabilities for the PUDs. Aggregated P90, P50 and P10 values were determined for each data set.

6. The aggregated P90 EUR was applied to each PUD as an expected result. The sum of (Aggregated P90 EUR X # of PUD's) and (mean EUR X # of existing wells) resulted in the Pool EUR.

Table B-1: Approximate Producing Well Count at Various Stages of Resource Play Development

	Phase of Resource Play Development			
	Early	Intermediate	Statistical	Mature
Ratio of Analogous Producing Wells To Recommended Minimum Sample Size	< 1	1 to 4	> 3	Very Large
P_{10}/P_{90} <4, Approximate Well Count	< 50	100	150	> 500
P_{10}/P_{90} 4 to 10, Approximate Well Count	< 50 - 200	100 - 400	150 - 600	> 1,000
P_{10}/P_{90} 10 to 30, Approximate Well Count	< 200 - 700	200 - 1,400	600 - 2,100	> 4,500

* Excerpt from SPEE Monograph 3

Table B-2: Recommended Maximum Number of PUD Offsets at Various Stages of Resource Play Development

	Phase of Resource Play Development			
	Early	Intermediate	Statistical	Mature
Recommended Maximum Number of PUD Offsets Per Producing Well (Vertical Wells)	4	8	Statistical	Statistical
Recommended Maximum Number of PUD Offsets Per Producing Well (Horizontal Wells)	2 - 4	4 - 8	Statistical	Statistical

* Excerpt from SPEE Monograph 3

Table B-3: Montney Reserves Results

Field	Pool	Mean EUR, MMSCF	P90 EUR, MMSCF	P50 EUR, MMSCF	P10 EUR, MMSCF	Pool EUR, BSCF	Pool Remaining Reserves BSCF	Existing HZ Wells	HZ PUDs	Existing Vertical Wells	Vertical PUDs
		Horizontal									
Heritage Montney	'A'	5,088	1,099	4,554	9,589	11,800	10,324	952	1,310	211	422
Northern Montney	DPM 'A'	4,684	1,048	4,236	8,492	1,899	1,763	138	276	12	24
Northern Montney	'A'	5,193	1,109	4,515	10,091	1,200	1,110	87	174	14	28

Figure B-1: Cumulative Probability Distribution of Montney EURs

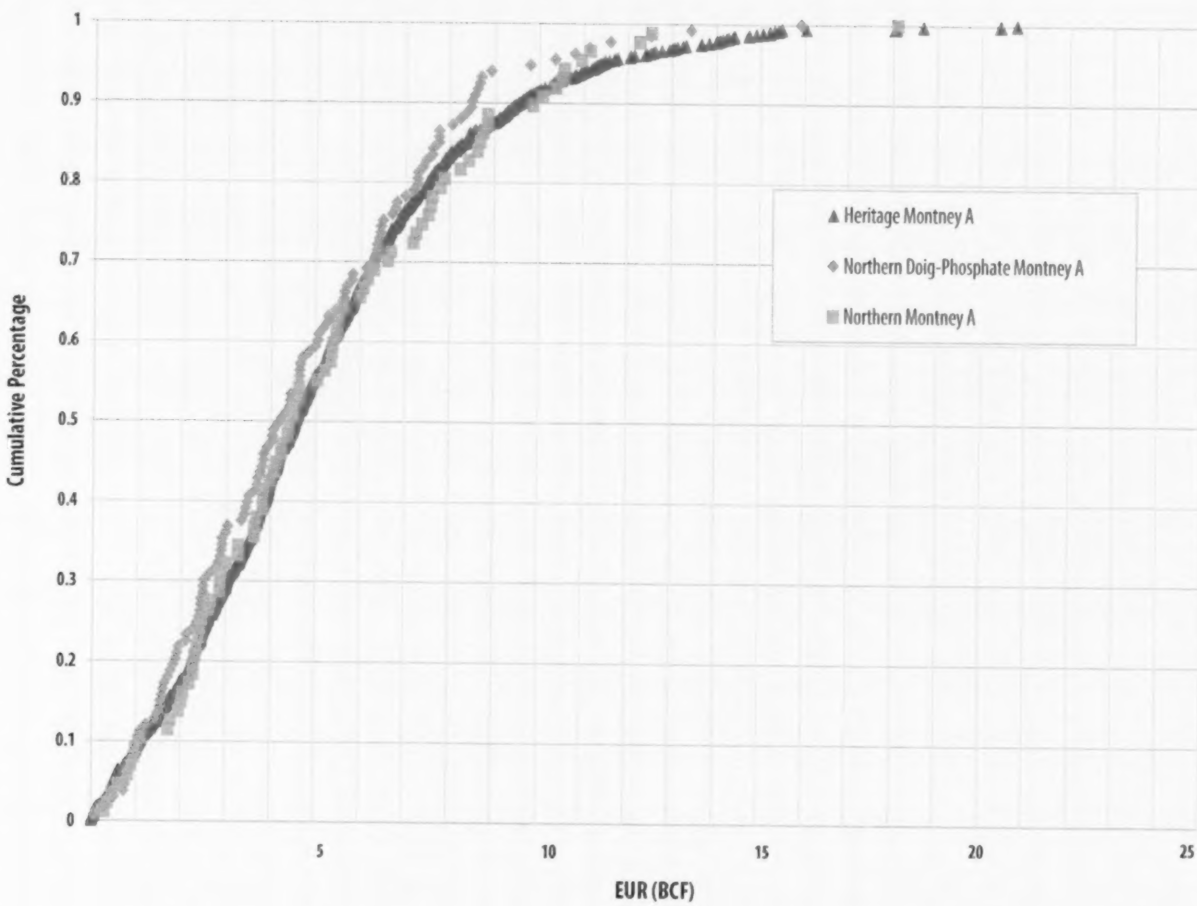


Figure B-2: Histograms of Montney EURs

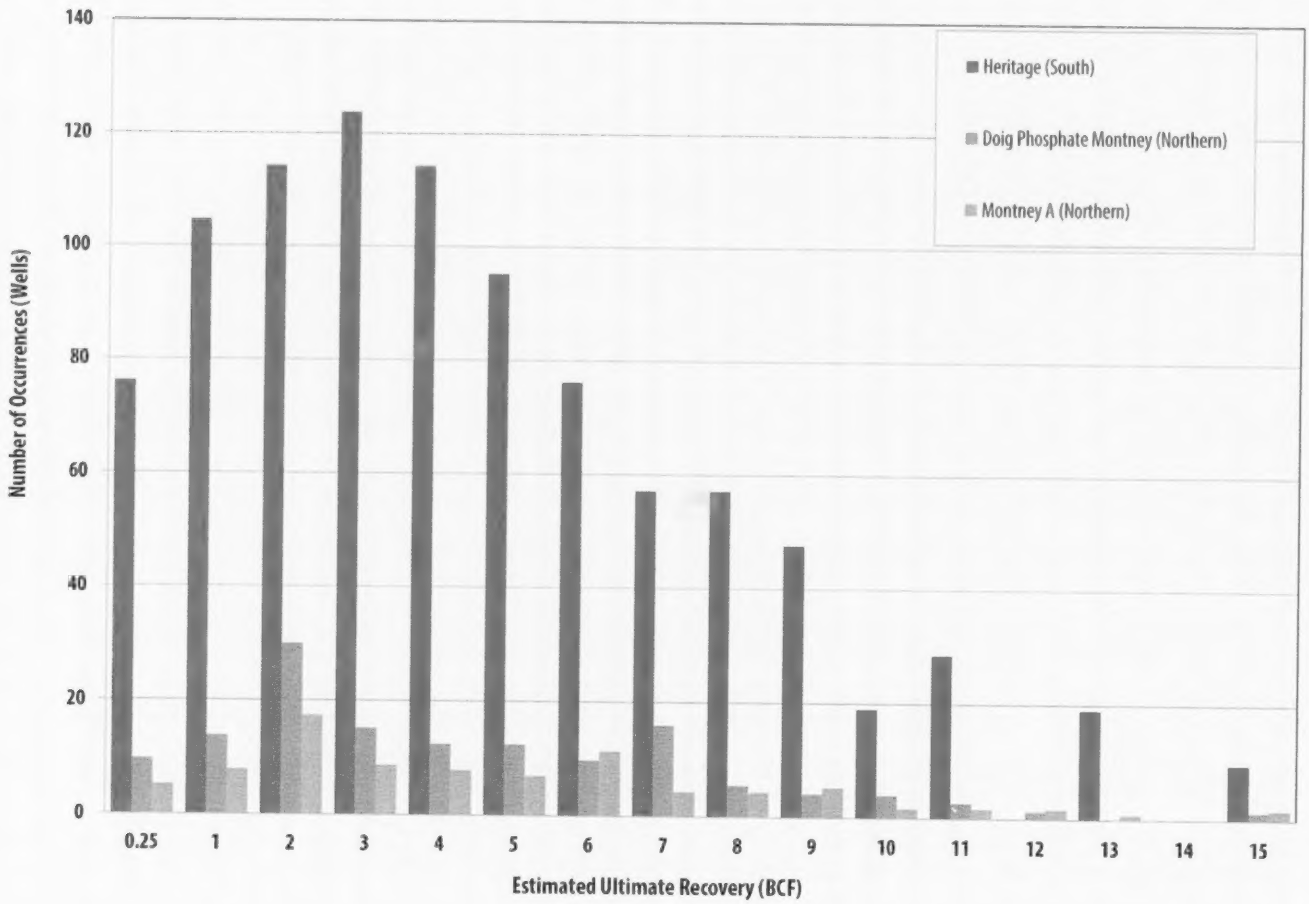


Figure B-3: Well Density Distribution in Regional Heritage Montney "A" Gas Pool

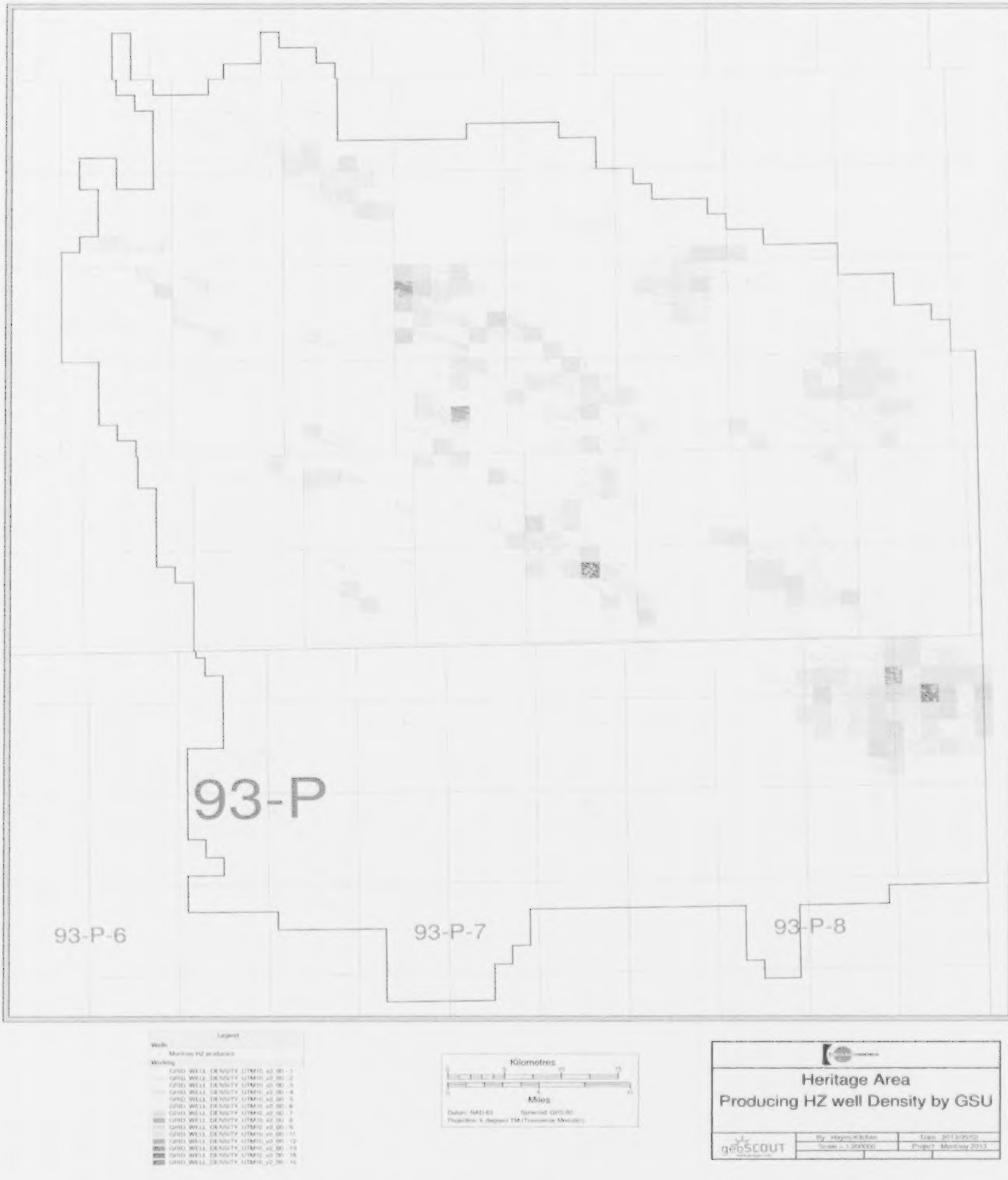


Figure B-4: Well Density Distribution in Regional Northern Montney Field

Table B-4: Summary of Unconventional Plays

	Montney	Horn River	Liard	Cordova
Prospective Resources				
Potential Resource (TCF)	1,965	448	210	200
Source	Joint 2013 report: Commission, AER, MNGD, NEB*	Joint 2011 report: NEB, MEM	Industry estimate, Commission evaluation ongoing	Preliminary Commission estimate
Proven Reserves				
OGIP (TCF)	124	46	1	0.2
RR (TCF)	13.4	11.1	0.1	0.03
Cumulative Gas (TCF)	1.6	0.4	0.007	0.01
Existing Wells Drilled	1,440	328	3	26
Reservoir Data				
Depth Range (m)	1,800 - 3,200	1,900 - 3,100	3,900 - 4,800	1,500 - 2,300
Gross Thickness (m)	30 - 300	140 - 280	145	70 - 120
TOC Range (%)	~2	1 - 5	3 - 6	2 - 5
Porosity (%)	2 - 9	3 - 6	3 - 6	3 - 6
Water Saturation (%)	25	25	15 - 20	25
Pressure (MPa)	20 - 50	20 - 53	77	15 - 20
Pressure Regime	Over pressure	Normal to over pressure	Over pressure	Normal
Temperature (° C)	60 - 100	80 - 160	150	80 - 120
Average H_2S (%)	< 0.3	0 Muskwa-Otter Park 0.07 Evie	0.002	0.00004
Average CO_2 (%)	< 1	10 Muskwa-Otter Park 12 Evie	7	8
Drilling Data (based on 2010-2012 results)				
Wells per pad	Up to 20	Up to 16	1	Up to 9
Average HZ length (m)	1600	1500	900	2100
Wellbore	Cased 75% Open hole 25%	Cased	Cased	Cased 80% Open hole 20%
Completion Data (based on 2010-2012 results)				
Fracture	Slickwater, gel/foam	Slickwater	Slickwater	Slickwater
Number of Stages	Up to 36, average 10	Up to 31, average 180	6	Up to 22, average 17
Pump Rate (m^3/min)	2 - 15	8 - 16	13	10 - 16
Average water per well (m^3)	9,000 slickwater, <2,000 gel/foam	64,000	23,000	43,000
Average sand per well (T)	1,300	3,700	1,500	4,100

* AER - Alberta Energy Regulator
MEM - B.C. Ministry of Energy and Mines
MNGD - B.C. Ministry of Natural Gas Development
NEB - National Energy Board

Table B-4: Summary of Unconventional Plays (continued)

	Montney	Horn River	Liard	Cordova
Production Data				
Average Peak Initial Rate ($10^3m^3/d$)	106	184	533	71
Average Well One Year Cumulative (10^3m^3)	24	40	85	19
Reserves Methodology				
Evaluation Method	Decline Statistics	Volumetric	Decline	Volumetric
Average Reserves Per HZ Well (10^6m^3)	142	N/A	538	N/A
Recovery Factor	12	25	N/A	25

Appendix C

C-1: Detailed Gas Reserves By Field and Pool available in both PDF and Excel version on Commission website.

C-2: Detailed Oil Reserves By Field and Pool available in both PDF and Excel version on Commission website.

C-3: Detailed Condensate and By-Product Reserves By Field and Pool available in both PDF and Excel version on Commission website.

More information

www.bcogc.ca

This report was published in December 2013 and is updated annually.

For specific questions regarding this document please contact:

Kelly Okuszko, P. Eng
Reservoir Engineer
Reservoir Engineering Department
BC Oil and Gas Commission
300, 398 Harbour Rd
Victoria, B.C. V9A 0B7
Phone: 250-419-4470 Fax: 250-419-4402
Kelly.Okuszko@bcogc.ca

BC Oil & Gas COMMISSION